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Preface

Pursuant to Section 205(h)(2) of the Department of Energy Organization Act, the Energy Information Administration, through Form EIA-28, has collected financial information and other measures of energy-related business efforts and results for major energy companies on a uniform, segmented basis. In 1989, 23 companies filed Form EIA-28. The comparability of information across energy lines of business is unique to this reporting system. For example, petroleum activities can be compared to activities in other energy lines of business or nonenergy areas, and domestic activities can be contrasted to foreign activities. The purpose of this publication is to examine year-to-year developments in the operations of the 23 major U.S. energy-producing companies on a corporate level, by major line of energy business, by major functions within each line of business, and by geographic area.

This report presents data collected on Form EIA-28 for the calendar year 1989. Although the focus is on developments in 1989, important trends within the 16-year period, 1974 through 1989, are also featured.

Economic performance, in financial and physical dimensions, continues to serve as a significant factor in evaluating past decisions and guiding future options in the development and supply of energy resources. The information contained in this report is intended to promote an understanding and a critical review of the possible motivations and apparent consequences of investment decisions by some of the largest corporations in the energy industry. The information is intended for use by the Congress, Government agencies, industry analysts, and the general public.

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Executive Summary

Performance Profiles of Major Energy Producers 1989 is the thirteenth annual report of the Energy Information Administration's (EIA) Financial Reporting System (FRS). The report examines financial and operating developments, with particular reference to the 23 major energy companies (the "FRS companies") required to report annually on Form EIA-28. Financial information is reported by major lines of business including oil and gas production, petroleum refining and marketing, and other energy operations. Domestic and international operations are examined separately in this report. It also traces key developments affecting the financial performance of major energy companies in 1989, as well as review of important trends.

Notable developments among the FRS companies in 1989 included:

- Environmental issues played a larger role in the FRS companies' performance in 1989.
- Apart from 1988, the FRS companies' overall profitability, as measured by return on equity, was at the highest level since 1981, the year of peak oil prices.
- For the first time over the 16 years of FRS data collection, the FRS companies' capitalized expenditures for foreign oil and gas production (including exploration and development) exceeded U.S. expenditures.
- Petroleum marketing was an important target of investment after many years as an area of net retrenchment.

Environmental Issues Gained Prominence

In 1989, environmental problems adversely affected the financial results of the FRS companies to a greater extent than in prior years. The net income of the FRS companies was reduced by $3.6 billion for special charges related to environmental matters. The charges resulted from provisions for damages related to the *Exxon Valdez* oil spill in Alaska's Prince William Sound in March of 1989, the writedowns of offshore Point Arguello (California) assets stemming from an environmentally-related change in State policy, and the provisions for future environmental clean-up costs, mainly for refining and chemical operations.

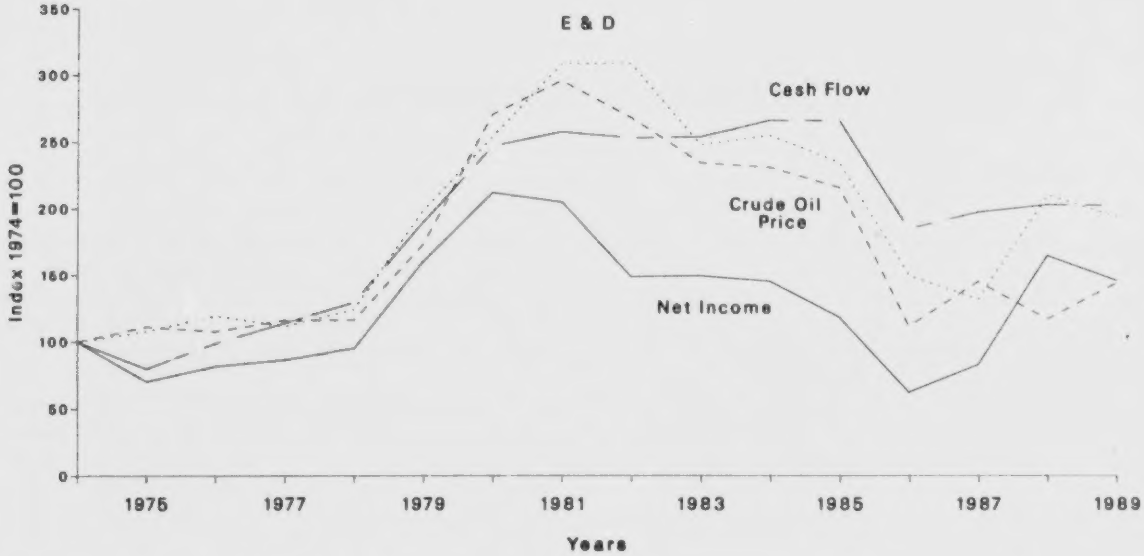
Reporting of capital expenditures for environmental protection purposes was much more frequent among the FRS companies in 1989 than in prior years. Fourteen companies reported capital expenditures for these purposes, totaling $1.6 billion, which represented 8 percent of their capital expenditures, excluding mergers and acquisitions. Eleven companies reported that their planned 1990 environmentally-related expenditures would be 58 percent above their 1989 spending.

In the global context, the U.S. offshore and arctic locales are world-class oil and gas provinces, with field sizes more comparable to those of major fields outside of North America than to the onshore United States and Canada. However, increased drilling restrictions in these areas, premised on environmental concerns, have narrowed the options available in the United States for significant additions to oil and gas reserves and, in part, have contributed to the increased emphasis by the FRS companies on foreign locales as a source of large oil and gas discoveries.

Income and Cash Flow

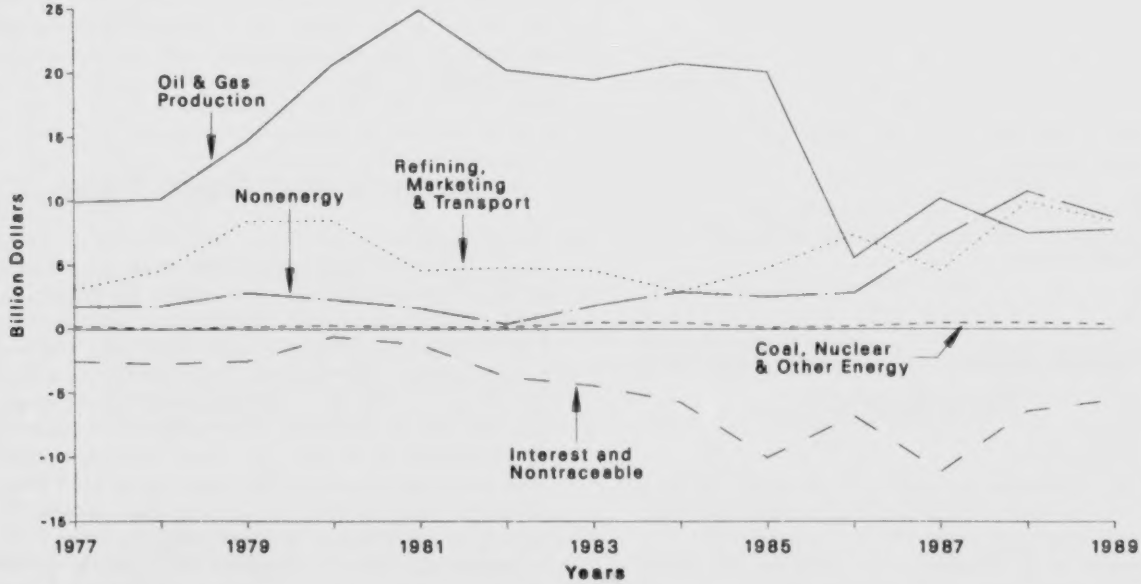
Despite a year-to-year increase in crude oil prices in excess of $3 per barrel, net income of the FRS companies fell 11 percent in 1989 from the prior year, to $19.8 billion. Nevertheless, apart from 1988, this was the highest level of net income since 1984 (Figure ES1) indicating that the FRS companies' investment strategies and restructuring efforts of recent years have led to a recovery in bottom-line financial results. Cash flow from operations in 1989 remained at $48 billion, about the same level as the previous year. Income for oil and gas production increased slightly, largely due to higher oil prices, but this gain was more than offset by reduced income from downstream petroleum operations (refining, marketing and transport) and nonenergy businesses (Figure ES2).

Figure ES1. Indexes of Crude Oil Prices and Financial Performance for FRS Companies, 1974-1989



Note: The crude oil price is the refiner acquisition cost of foreign crude oil. Exploration and development (E&D) expenditures exclude purchases of proved acreage. Cash flow is measured as funds from operations (1974-1985) and net cash flow from operations, (1986-1989)
Sources: o Financial measures: Energy Information Administration, Form EIA-28. o Crude oil price: Energy Information Administration, *Annual Energy Review, 1989*,DOE/EIA-0384(89) (Washington, DC, May 1990).

Figure ES2. Sources of Net Income for FRS Companies



Source: Energy Information Administration, Form EIA-28.

Although gasoline prices rose briefly, following the *Exxon Valdez* oil spill, and heating oil prices rocketed during the record December cold spell, overall refined product price increases merely matched crude oil price rises over the course of 1989. However, the FRS companies' costs of operating their U.S. refining and marketing networks rose between 1988 and 1989, mainly due to an increased need to purchase refined products. As a result, the FRS companies' income from downstream petroleum operations fell from the record level of 1988. Chemical operations were adversely affected by the combination of reduced industrial growth, higher feedstock costs, and increased industry capacity in 1989.

Capital and Exploration Expenditures

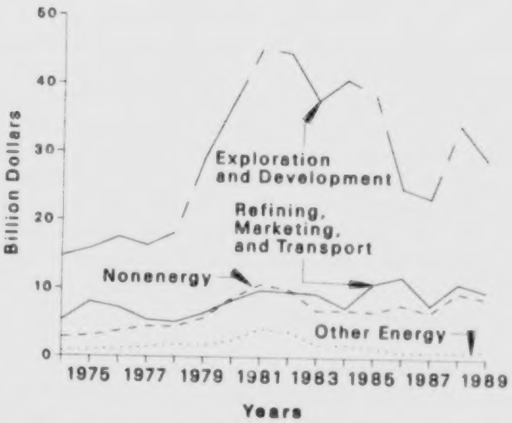
The FRS companies' capital expenditures totaled $45 billion in 1989. Capital expenditures were down 9 percent from the prior year, mainly due to reduced spending for mergers and acquisitions in 1989. Excluding the effects of mergers and acquisitions, capital expenditures increased 4 percent to the highest level since 1985. Expenditures for mergers and acquisitions were unusually large in 1988, largely because FRS companies spent $5.4 billion for petroleum assets sold by Tenneco. In 1989, the largest single transaction was Exxon's acquisition of Texaco Canada for $4.2 billion. Texaco sold its Canadian subsidiary as part of its restructuring efforts and utilized the proceeds to pay special dividends to shareholders, reduce debt, and initiate a stock repurchase program.

Upstream Investment Increases Outside of the United States

Exploration and development, directed toward the discovery and development of additional oil and gas reserves, accounted for the bulk of the FRS companies' expenditures (Figure ES3). On a worldwide basis, the FRS companies reduced their exploration and development expenditures by $5 billion, to $29 billion. However, results differed considerably between the United States and foreign areas.

Since early 1986, the FRS companies have increasingly shifted their exploration and development investments toward foreign locales. Lower oil prices have had the effect of reducing the overall profitability of oil and gas investment but also have made prospects with large field sizes relatively more attractive as investment targets. Generally, oil and gas fields outside of North America tend to be larger. Additionally, foreign areas typically require lower front end costs to obtain exploration rights and a number of foreign jurisdictions reduced their rates of upstream taxation in recent years. In response to the changing economics of exploration and development, the FRS companies increased the share of their exploration and development expenditures for foreign areas from 26 percent in 1985 to 49 percent in 1989. Capitalized expenditures (that is, exploration and development expenditures excluding exploration expenses) for foreign oil and gas production in 1989 exceeded capitalized expenditures for U.S. oil and gas production for the first time over the 1974 through 1989 period encompassed by the FRS data collection. The FRS companies' foreign exploration and development expenditures increased by over $1 billion to $14 billion, between 1988 and 1989.

Figure ES3. Capital and Exploration Expenditures by Line of Business for FRS Companies, 1974-1989



Note: Excludes effects of intra-FRS mergers in 1982 and 1984.
Source: Energy Information Administration, Form EIA-28.

The FRS companies' U.S. exploration and development expenditures declined by $6 billion, to $15 billion in 1989. Two-thirds of the decline came from reduced expenditures for acreage. Other categories of U.S. expenditures which were much reduced from 1988 included exploratory offshore drilling and drilling of development oil wells onshore. Offshore exploration drilling was at a heightened level in 1988 due to the large number of Federal Outer Continental Shelf (OCS) leases that would have expired in 1988 if exploration on them had not occurred. The drop in development oil drilling was a continuation of the effects of low oil prices that began in 1986.

Finding Costs Remain Low

During the period of declining oil prices, which began in early 1981, and particularly since the oil price crash of 1986, the FRS companies have made substantial adjustments in their exploration and development strategies. Of particular importance has been an increased focus on larger oil and gas fields and elimination of smaller field prospects that have tended to be uneconomic in the context of lower oil prices. Consequently, as oil prices declined, finding rates (reserves added per well) have increased.

Over the same period that finding rates have increased, the costs of drilling and lease acquisition have fallen far below the levels that prevailed in the period of peak oil prices. As a result, the FRS companies' costs of adding oil and gas reserves through exploration and development have been on a downward trend in the 1980's. The 1987 through 1989 weighted average U.S. finding costs (exploration and development expenditures in 1989 dollars divided by reserve additions) of the FRS companies were $4.59 per barrel, over a dollar less than for the previous 1986-1988 period, and 70 percent less than the peak value of finding costs of the 1980 through 1982 period. Abroad, finding costs also fell, but at a lesser rate.

Although the number of U.S. wells completed by the FRS companies declined by 20 percent, in 1989, oil and gas reserve additions (on an energy-equivalent basis) fell a lesser 14 percent, to 2.7 billion barrels. Abroad, the FRS companies' oil well completions declined by 36 percent, in 1989. The decline was almost entirely concentrated in Canada where finding rates tend to be relatively low. Foreign oil and gas reserve additions of the FRS companies declined only 5 percent between 1988 and 1989, to 2.0 billion barrels.

Marketing Expenditures Match Record Level

The generally lower level of petroleum prices in recent years stimulated U.S. gasoline consumption. This development created renewed opportunities for growth and profitable investment in gasoline marketing in contrast to the past decade when marketing was an area plagued by excess capacity, low profitability, and retrenchment. In responding to these opportunities, the FRS companies have emphasized their company-operated retail operations. These operations accounted for 49 percent of the increase in their total gasoline sales volumes between 1985 and 1989. Capital expenditures of $2.8 billion for petroleum marketing operations in 1989 essentially matched the record level of 1988.

Restructuring and Recent Performance Raise Market Value

In 1989, the FRS companies' dividends to shareholders increased by over $4 billion, following a $2 billion increase in 1988. Over 90 percent of the FRS companies increased their dividend payments between 1988 and 1989. Stock repurchases, though down slightly from 1988, totaled over $6 billion. Two-thirds of the FRS companies repurchased their stock in 1989. Asset sales and sales of ownership interests in subsidiaries continued to be a significant source of cash in 1989, providing $13 billion in funds. Investment was concentrated in petroleum and chemicals which accounted for 90 percent of the FRS companies' investment expenditures in 1989.

Through most of the 1980's, the decline in oil prices eroded the profitability of upstream petroleum, which was the FRS companies' major source of earnings. In addition, large-scale diversification efforts often proved to be unprofitable. Large amounts of excess capacity prevailed in their refining and marketing operations. In this context stockholder discontent was severe and inspired a rash of takeover attempts by corporate raiders promising new management strategies. As a result, some companies were merged and others undertook major restructuring efforts. During the most intense period of restructuring, 1984 through 1986, the FRS companies accumulated large amounts of debt.

In recent years, the FRS companies have attempted to contain their growth in debt. At the same time, they have increased their profitability by concentrating their investment outlays in petroleum and chemicals. They have also increased shareholder valuation through increased dividends and purchases of their own stock.

The FRS companies' restructuring efforts and investment strategies have improved their standing in the capital markets. The market value of the FRS companies' common stock (relative to the book value of the company) rose 45 percent between 1986 and 1989, while the comparable rise for the Standard and Poor's (S&P) group of 400 industrial companies (excluding the FRS companies) was only 7 percent. By contrast, between 1981 and 1985, the FRS companies' market value was frequently below their book value while for the S&P group, market value (relative to book value) rose over 50 percent, buoyed by a strong stock market following the 1981-1982 recession. The FRS companies' debt, relative to equity, has shown little change since 1985, indicating that their efforts to contain their growth in debt have worked. For the S&P group, debt (relative to equity) continued to grow in 1989. The profitability of the FRS companies in 1989, as measured by return on equity, though down slightly from 1988, was, excluding 1988, at the highest level since 1981. Nevertheless, their profitability was still somewhat below that of the S&P group.

1. Introduction

Major energy companies annually report to the Energy Information Administration (EIA) on Form EIA-28. These company reports include data and information on their financial and operating developments. For the reporting year 1989, 23 companies filed this information.[1] The EIA Financial Reporting System (FRS) program maintains a data base of this information covering developments since 1974.[2] The analysis and data presented in this report depict the operations of the FRS companies in the context of their worldwide operations and in the context of the major energy markets which they serve. The report analyzes the energy and nonenergy developments of the FRS companies, developments in their major lines of business and in segments within the petroleum line of business, and developments across geographic areas in which they operate.[3]

The 23 FRS companies occupy a major position in the U.S.[4] economy. In 1989, their sales were equal to 20 percent of the $2.2 trillion in sales by Fortune's list of the 500 largest U.S. industrial corporations, and their profits and assets were each equal to 19 percent of those of the Fortune 500 companies. Of the top 25 industrial companies (based on sales) on the Fortune 500 list in 1989, 10 were FRS companies.

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 79 percent, or $351 billion, of allocated operating revenues were derived from energy sales. Nearly all of these sales involve petroleum (Figure 1). (For purposes of this report, petroleum is defined to include natural gas.)[5]

In 1989, the FRS companies accounted for 58 percent of total U.S. crude oil and natural gas liquids production, 44 percent of U.S. natural gas production,[6] and 71 percent of U.S. refinery capacity (Figure 2). The bulk of the FRS companies' assets, as well as their new investments, is devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy businesses accounted for about 21 percent, or $94 billion, of the FRS companies' allocated revenues in 1989.

Relative to petroleum, production of nonpetroleum energy by FRS companies is not large. The combined operating revenues of coal, nuclear, and nonconventional energy operations of the FRS companies totaled $7.9 billion in 1989, or slightly less than 2 percent of allocated revenues. Nonetheless, FRS companies are significant participants in these markets. For example, the FRS companies produced 29 percent of all U.S. coal in 1989 and 23 percent of all U.S. uranium oxide. However, these and other nonpetroleum energy activities did not contribute greatly to the total profits of the FRS companies.

[1] The companies that reported to the FRS system for the years 1977 through 1989 are listed in Appendix A.

[2] In addition to the data provided by the detailed statistical tables in Appendix B and in the appendices of previous versions of this report, aggregate time series data from Form EIA-28 are available in a special post embargo report covering the period 1974 through 1980. See Energy Information Administration, *Energy Company Development Patterns in the Post-embargo Era*, Vol. 1 and Vol. 2, DOE/EIA-039. Also, data for 1977 through 1983 were published in Energy Information Administration, *Performance Profiles of Major Energy Producers 1983*, Volume 2, DOE/EIA-0206(83/2). Additionally, aggregate time series data from Form EIA-28 for 1974 through 1989 can be obtained from the EIA (see Contacts, p. ii).

[3] The requirement to collect and analyze information is in Public Law 95-91, August 4, 1977, the Department of Energy Organization Act, 91 Stat. 573.

[4] For purposes of this report, the term "United States" typically includes the 50 States, the District of Columbia, Puerto Rico, and the U.S. Virgin Islands.

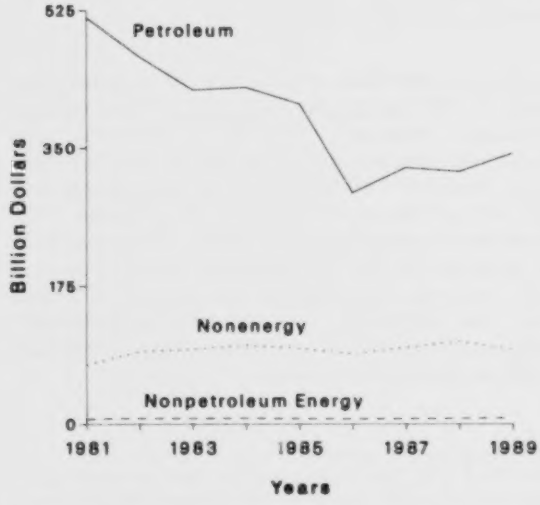
[5] Natural gas and oil are collectively referred to as petroleum since many of their financial aspects cannot be separated. However, data on sales, production, resource development, and reserves are collected separately for oil and gas and are discussed in subsequent chapters.

[6] The data for total U.S. production of crude oil and natural gas liquids and of natural gas (dry) in this report are taken from the Energy Information Administration (EIA), *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1989 Annual Report, DOE/EIA-0216(89). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and of production reported elsewhere in this report. However, the official EIA U.S. totals for crude oil and natural gas plant production are 3,364.9 million barrels in 1989 and 3,593.4 million barrels in 1988 (EIA, *Petroleum Supply Annual 1989*, Vol 1, DOE/EIA-0340(89)/1). For dry natural gas production, the official EIA U.S. totals are 17,115 billion cubic feet in 1989 and 16,992 billion cubic feet in 1988 (EIA, *Natural Gas Monthly*, June 1990 DOE/EIA-0130(90)/06). The EIA official totals were developed from data provided by Federal and State oil and gas regulatory agencies, whereas the EIA reserves report totals were developed from data collected in EIA survey Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." Differences between these totals are briefly noted and discussed on pages 43-44 and 46 of the 1989 EIA reserves report.

Overall, 1989 was a year of declining profitability for the FRS companies despite a rise in crude oil prices. Net income fell by about 11 percent, to $19.8 billion. About 40 percent of the decline in net income was due to deteriorating operations in various lines of business (see Chapter 2). For example, substantial decreases in profits occurred in the nonenergy sector, particularly in petrochemicals where crude oil feedstock costs rose and product prices fell as a result of weak demand and increased capacity. Substantial reductions also occurred in the petroleum sector, where a decrease in profits from refining operations more than offset the favorable effects of an increase in crude oil prices in the petroleum production segment. Unusual, or nonrecurring, items also depressed earnings and accounted for another 40 percent of the decline in net income. The unusual items were concentrated in the petroleum line of business. They included environmental charges against income, such as the clean up and other liabilities associated with the Exxon Valdez oil spill. They also included a sharp reduction in net income from discontinued operations, principally reflecting Tenneco's sale of its petroleum assets a year earlier.

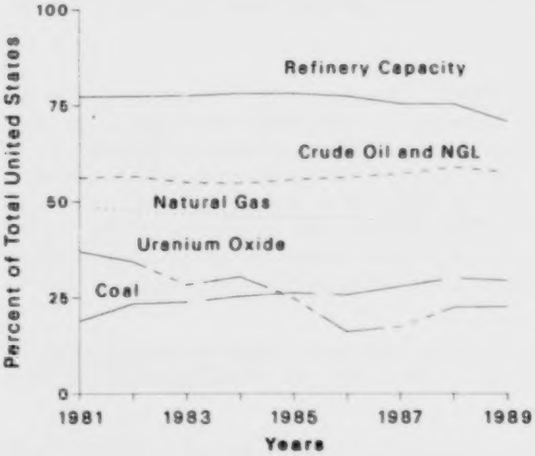
A higher aggregate effective tax rate also depressed earnings, and accounted for about 20 percent of the decrease in FRS net income. Most of the increase in the effective rate occurred in the high-tax-rate foreign petroleum production segment and from an increase in the relative importance of that segment in overall FRS operations.

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1981-1989



Source: Energy Information Administration, Form EIA-28.

Figure 2. FRS Companies' Share of U.S. Energy Production and Refinery Capacity, 1981-1989



Note: A new series for Uranium Oxide begins in 1986.
Source: See Table B1, Appendix B.

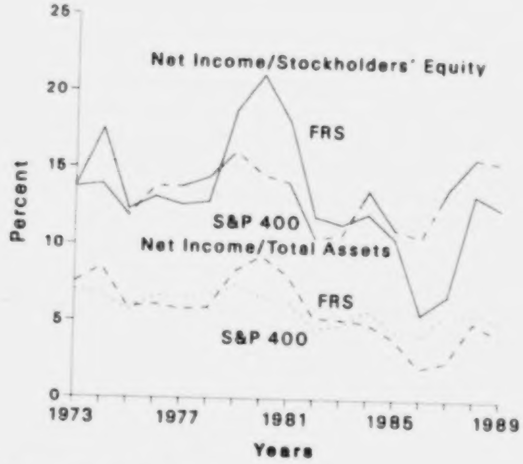
2. Key Financial Trends

Despite a substantial rise in crude oil prices, the income and profitability of the FRS companies, in 1989, fell short of their financial performance in the previous year. Throughout most of 1989, crude oil prices rose in response to a slowdown in the growth of world oil production. By December 1989, oil prices were roughly $5 per barrel above the December 1988 level, and, on an annual basis, oil prices were $3 per barrel higher for 1989 compared with 1988. The rise in oil prices financially benefited the FRS companies' oil and gas production operations even though their production of oil and gas declined. However, gains in income from oil and gas operations were more than offset by reduced income from downstream petroleum operations (refining, marketing, and transport) and nonenergy businesses, including chemicals.

In the Spring of 1989, reactions to the *Exxon Valdez* oil spill led to a sharp, but short-lived, rise in gasoline prices, and, in December, record cold weather resulted in a substantial increase in heating oil prices. Although petroleum product prices were up in 1989, the overall rise in product prices only matched the increase in crude oil prices over the course of the year. The FRS companies' downstream petroleum operations incurred higher costs due to provisions for future environmental cleanup expenses and a heightened level of product purchases which resulted in a decline in income from these operations. Nonenergy businesses were adversely affected by a general economic slowdown and chemical operations also were impaired by higher feedstock costs. Other industrial companies' net income, as represented by the Standard and Poor's (S&P) 400 industrials,[7] fell at a lesser rate, which led to a somewhat wider gap in profitability between the two groups of companies in 1989 (Figure 3). Nevertheless, apart from 1988, the FRS companies' corporate profitability in 1989 was at the highest level since 1981.

The FRS companies' overall capital expenditures in 1989 were down 9 percent, to $45 billion, because merger and acquisition activity was considerably reduced from the high level of the previous year. Excluding the effects of mergers and acquisitions, capital expenditures of the FRS companies rose 4 percent, to the highest level since 1985. The largest increase in capital expenditures was for foreign oil and gas operations, while U.S. oil and gas production registered the largest decline. As a result of this development in 1989, the FRS companies' expenditures for foreign oil and gas production exceeded their U.S. expenditures for the first time over the 16 years spanned by the FRS data collection.

Figure 3. Selected Performance Measures for FRS Companies and the S&P 400, 1973-1989



Sources: o FRS Companies - Energy Information Administration, Form EIA-28
o S&P 400 - Standard & Poor's Compustat Services, Inc.

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[7] The S&P 400 is a well recognized data base that includes 400 of the largest U.S. industrial companies. In 1989, 16 of the FRS companies were included in the S&P 400. Financial statistics for the S&P 400 were obtained by accessing Compustat, a service of Standard & Poor's Inc.

Sources of Revenue and Income

Trends in the 1980's

The composition of the FRS companies' net income has changed dramatically in the context of the low oil prices of the 1986 through 1989 period. Prior to the oil price crash of early 1986, over three-quarters of the FRS companies' income, allocated to their lines of business, was derived from oil and gas production. Since then, upstream petroleum operations have accounted for only about one third of their total line-of-business net income. This shift is primarily traceable to lower oil prices and, to a lesser extent, a general decline in their oil and gas production. By contrast, downstream petroleum (refining, marketing, and transport) and chemical operations have become much more important as sources of earnings for the FRS companies. In the 1981 through 1985 period, refining and marketing operations underwent substantial adjustments. Excess refining and marketing capacity was largely eliminated and the remaining capacity was upgraded to produce more unleaded gasoline and other higher-end products and to process a greater variety of crude oil qualities. Lower oil prices have served to increase petroleum demand, particularly gasoline, and increase refinery capacity utilization rates. Chemical operations benefited from lower feedstock costs, following the drop in oil prices, while industrial growth has increased the demand for chemical products. In the 1981 through 1985 period, slightly over 20 percent of the FRS companies' total line-of-business income came from downstream petroleum and chemical operations. However, over the 1986 through 1989 period of lower oil prices, the comparable share tripled, to 60 percent. As a result of these developments, the strong, positive relationship between the net income of FRS companies and crude oil prices of the 1974 through 1987 period was reversed in 1988 and 1989.

Overall Results for 1989

The FRS companies' total revenue was up 3 percent, to $433.6 billion in 1989 (Table 1). Higher prices for crude oil and petroleum products more than offset declines in oil and gas production and petroleum product sales volumes, resulting in a rise in overall petroleum revenues (Figure 1). Nonenergy revenues declined, in part from reduced chemical product sales and in part from a change in the FRS survey group.

Net income of the FRS companies totaled $19.8 billion in 1989, 11 percent below the level of 1988. However, apart from 1988's results, this was the best showing since 1984, when crude oil prices averaged in excess of $10 per barrel more than in 1989. Unusual items accounted for about 40 percent of the decline in net income between 1988 and 1989 (Table 2). Unusual items are composed of gains and charges recognized in a company's income statement which are of a nonrecurring nature and generally unrelated to current operations. These items include litigation settlements, gains and losses from large divestitures of assets, provisions for the cost of restructuring, and provision of reserves for future liabilities. In 1989, the after-tax effect of unusual items reduced the FRS companies' net income by $845 million.

Table 1. Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1989

Selected Financial Items	All FRS Companies		S&P 400		Non-FRS S&P 400[a]	
	1989 (billion dollars)	Percent Change From 1988	1989 (billion dollars)	Percent Change From 1988	1989 (billion dollars)	Percent Change From 1988
Income Statement						
Operating Revenues	433.6	3.3	2,350.1	5.0	1,989.2	5.0
Operating Expenses	-397.7	4.2	-2,107.8	5.0	1,776.3	4.7
Operating Income	35.9	-6.1	242.3	4.8	212.9	6.9
Other Income[b]	-3.1	NM	-50.8	NM	-49.3	NM
Income Taxes	-13.0	-3.6	-68.7	1.0	57.4	2.0
Net Income	19.8	-11.4	122.9	-4.5	106.1	-3.0
Funds from Operations	48.3	-0.7	209.3	-3.9	170.5	-4.5

[a] S&P 400 excluding FRS companies. Sixteen FRS companies are included in the S&P 400 group.
[b] "Other Income" includes other revenue and expense, extraordinary items, and accounting changes.
NM = Not meaningful.
Sources: FRS companies: Energy Information Administration, Form EIA-28. S&P 400: Standard & Poor's Compustat Services, Inc.

Table 2. Effect of Unusual Items on the Consolidated Net Income of FRS Companies, 1984-1989
(Million Dollars)

Net Income and Unusual Items[a]	1984	1985	1986	1987	1988	1989
Net Income Before Unusual Items	23,600.6	22,479.5	13,885.9	16,213.0	22,155.0	20,629.0
Unusual Items, After Tax[a]	-2,291.7	-5,099.9	-4,719.3	-4,956.0	184.0	-845.0
Net Income	21,308.9	17,379.6	9,166.6	11,257.0	22,339.0	19,784.0

[a] Unusual items include discontinued operations, writedowns of asset values, provisions for regulatory and litigation matters, personnel reduction costs, extraordinary items, and effects of accounting changes.

Sources: Energy Information Administration, Form EIA-28 and company annual reports to shareholders.

Environmental Factors Hurt Bottom-Line Results

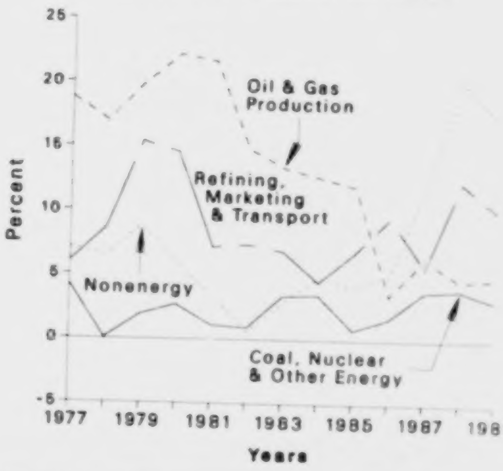
Most of the unusual charges against the FRS companies' net income in past years involved restructuring and writedowns of assets to realizable market values. The year 1989 was atypical in that the bulk of unusual charges resulted from environmental factors. Over $3.6 billion of after-tax unusual items, recognized as charges against income, stemmed from developments related to environmental costs and policies. Among the FRS companies, Exxon had an after-tax charge against income of $1.7 billion related to clean up and other liabilities resulting from the *Exxon Valdez* oil spill in Alaska's Prince William Sound in March of 1989. In California, restrictions were placed by the State on the transport of oil from the offshore Point Arguello Field due to environmental concerns. Chevron and Phillips Petroleum wrote off a total of $735 million against net income to recognize the economic impairment of their Point Arguello assets. Chevron also had a provision of $356 million for future environmental cleanup of downstream petroleum operations which was taken as a charge against net income. Texaco reported a charge against income of over $600 million for the provision of reserves for environmental clean up. The largest positive unusual item was Texaco's after-tax gain of $1.3 billion from the sale of their subsidiary, Texaco Canada, to Exxon's Imperial Oil.

Line-of-Business Results

In 1989, for the third consecutive year, the nonenergy activities of the FRS companies yielded the highest rate of return (Figure 4). The generally improved financial performance of this line of business reflected a combination of strong demand for chemicals in recent years and restructuring efforts in which unprofitable diversified businesses were divested. Although down somewhat from the prior year, the rate of return for downstream petroleum in 1989 was considerably above the levels of the 1981 through 1987 period. Substantial adjustments to refinery capacity throughout most of the decade and a resultant improvement in utilization rates and price-cost margins underlay this recent trend. Until the oil price crash of 1986, oil and gas production was the most profitable of the FRS companies' operations. Since 1986, crude oil prices have remained low and the rate of return to oil and gas has remained well below pre-1986 levels, although profitability improved in 1989.

The remainder of this section reviews the factors affecting the financial performance of the FRS companies' lines of business in 1989. For some lines of business, reported net income was strongly affected by unusual items. In order to better examine the results of operations, the review in this section will focus on net

Figure 4. Rates of Return by Line of Business for FRS Companies, 1977-1989



Note: Net income contribution divided by net investment in place.

Source: Energy Information Administration, Form EIA-28.

income[8] excluding the effects of unusual items.

Oil and Gas Production. Excluding the effects of unusual items, the FRS companies' net income from U.S. oil and gas production more than doubled between 1988 and 1989 (Table 3). The bulk of the improvement was attributable to higher oil prices, which rose $2.41 per barrel for the FRS companies. Lower exploration expenses (including dry hole costs) contributed slightly to the improvement in income. Improvement was restrained by lower natural gas revenues, which resulted from reduced production and flat year-to-year movement in natural gas prices, and somewhat higher production costs.

Abroad, the FRS companies' upstream income also increased, but at a lesser pace. Higher overhead expenses and capital recovery costs (depreciation, depletion, and amortization) partially offset the effects of higher oil prices. Also, net gains from asset sales in foreign oil and gas production operations were nearly $700 million less in 1989 compared with 1988.

Table 3. Contributions to Net Income by Line of Business for FRS Companies, 1988-1989
(Million Dollars)

Line of Business	Net Income			Net Income Excluding Unusual Items		
	1988	1989	Percent Change 1988-1989	1988	1989	Percent Change 1988-1989
Petroleum						
U.S. Petroleum						
Production	3,166	3,051	-3.6	1,888	4,079	116.0
Refining/Marketing	5,443	4,522	-16.9	5,314	5,000	-5.9
Pipelines	1,981	1,904	-3.9	2,463	1,904	-22.7
Total U.S. Petroleum	10,581	9,497	-10.2	9,836	11,003	11.9
Foreign Petroleum						
Production	4,337	4,714	8.7	4,390	4,795	9.2
Refining/Marketing	2,427	1,816	-25.2	2,428	1,865	-23.2
International Marine	118	218	84.7	108	218	101.9
Total Foreign Petroleum	6,889	6,710	-2.6	6,933	6,840	-1.3
Total Petroleum	17,470	16,207	-7.2	16,769	17,843	6.4
Coal	586	441	-24.7	605	613	1.3
Nuclear and Other Energy	-84	-70	NM	-78	-53	NM
Nonenergy	10,767	8,737	-18.2	10,662	9,010	-15.5
Total Allocated	28,739	25,315	-11.9	27,958	27,413	-1.9
Allocated Unusual Items, After Tax	--	--	NM	781	-2,098	NM
Nontraceables and Eliminations	-6,400	-5,531	NM	-6,400	-5,531	NM
Consolidated	22,339	19,784	-11.4	22,339	19,784	-11.4

-- = Not applicable.
NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding and/or nontraceables and eliminations.
Source: Energy Information Administration, Form EIA-28.

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[8] Line-of-business profit measures should be distinguished from measures which reflect companywide results because the former reflect only allocated income, expense, and asset items. Two measures of income are presented: *operating income* and *contribution to net income*. *Operating income* by line of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amortization) for a line of business. *Contribution to net income* equals operating income plus income from unconsolidated affiliates and gains on disposal of property, plant, and equipment (PP&E) less income taxes imputed to the line of business and excludes certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a companywide net income figure and line-of-business contributions to net income (see Appendix A for further discussion). Line-of-business rates of return are calculated as the line-of-business contribution to net income divided by net investment in place for the line of business. This latter value is equal to the value of net property, plant, and equipment (PP&E) plus the value of investments and advances to unconsolidated affiliates for the line of business.

Refining and Marketing. Net income from the FRS companies' U.S. refining/marketing operations did not quite match the record performance of 1988. Nevertheless, U.S. refining/marketing profitability was high in the context of the 1980's. As discussed in detail in Chapter 4, the FRS companies' margin between refined product revenues and costs deteriorated in 1989. The main factor in this decline was an increase in refined product purchases, in part due to the need for some companies to obtain heating oil supplies during the record cold weather in December.

Lower sales volumes also reduced the FRS companies' refining/marketing income. Refined product sales volumes, which hardly changed for the United States as a whole between 1988 and 1989, declined by 4 percent for the FRS companies. The decline in product volumes stemmed from ownership changes in 1989: ARCO spun off their Lyondell Petrochemical subsidiary through an initial public offering of stock, the Star Enterprise joint venture between Texaco and Saudi Arabia's Aramco (formed in 1988) began operations in 1989, and the Uno-Ven joint venture deal between Unocal and Petroleos de Venezuela was completed in 1989.

Foreign refining/marketing net income of the FRS companies also declined from 1988 but was still above the levels of most years of the 1980's. Higher operating expenses wiped out the gains in revenues in 1989, indicating that crude oil cost increases were not fully recouped through higher product prices. Although the utilization rate for the FRS companies' foreign refineries remained relatively high in 1989, their foreign refined product output declined by nearly 6 percent due to net divestitures of foreign refinery capacity.

Transportation. The apparent performance of the FRS companies' rate-regulated pipelines operations was somewhat affected by Tenneco's absence as an FRS respondent in 1989.[9] However, even excluding Tenneco, net income from pipelines registered a 16-percent decline. In natural gas transmission operations, deregulation has resulted in an increasing share of revenues derived from transport and a lesser share from direct sales of natural gas. Natural gas transport tends to yield smaller profit margins thereby reducing income. This trend continued in 1989. Financial results for liquids pipelines were adversely affected by lower transport volumes, due to reduced U.S. crude oil production, and lower tariff rates for the Trans Alaskan Pipeline System.

For most years of the 1974 through 1989 FRS data collection period, the FRS companies' international marine operations registered negative rates of return. The poor performance was related to the overhang of excess shipping capacity which was prolonged by the relatively long operating lives of tankers. In recent years, volumes of internationally transported oil increased in response to the low level of oil prices subsequent to the oil price crash of 1986. Also, lower oil prices have reduced tanker fuel costs, an important component of operating costs. Net income from the FRS companies' international marine operations doubled between 1988 and 1989, to the highest level since at least 1977. In 1989, the international marine segment had the highest rate of return among the FRS companies' petroleum lines of business.

Coal and Other Energy. The 17 coal producers among the FRS companies experienced mixed financial results in 1989. The FRS companies' U.S. coal production rose by less than 1 percent while total U.S. coal production grew by over 3 percent (see Chapter 7). However, U.S. consumption of coal rose by only 1 percent in 1989, due to lessened growth in electricity generation and a rebound in hydroelectric generating capability, which put downward pressure on coal prices. Also, a number of coal producers were adversely affected by work stoppages in 1989. Offsetting these developments was a continued growth in productivity stemming from western coal production and installation of long-wall mining equipment. Coal exports were a source of increased sales volumes, growing 6 percent between 1988 and 1989. On balance, the FRS companies' net income from coal operations in 1989, excluding unusual items, was up 1 percent, to $613 million.

Most of the revenues of the FRS companies' other energy operations, in 1989, came from sales of oil produced from Canadian tar sands and production of electricity from geothermal energy sources. Of lesser importance were ongoing operations in uranium production, solar power manufacturing, oil shale development projects, and cogeneration. Net losses from the FRS companies' other energy operations lessened in 1989, compared with 1988. The improvement was concentrated among companies involved in tar sands production and geothermal power, and resulted from higher sales prices.

Nonenergy. The profitability of the FRS companies' nonenergy line of business has increased since 1982 and surpassed the profitability of all of their energy lines of business beginning in 1987 (Figure 4). Two long-running developments underlay this trend. First, chemical operations benefited from increased demand, stemming from a recovery in worldwide industrial production in recent years, and lower feedstock costs due to the reduced level of oil prices since 1986. The result has been a greater spread between revenues and costs, particularly from 1986 on (Figure 5). Second, most FRS companies massively restructured their diversified businesses, selling unprofitable operations and other businesses that were not deemed integral to long-term investment strategies. As a consequence, the remaining diversified businesses have contributed to increased profitability.

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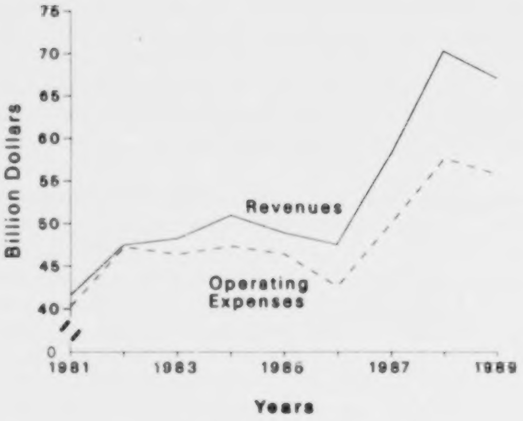
[9] Tenneco was deleted as an FRS respondent in 1989 due to the sale of their petroleum assets in 1988. Total Petroleum North America was added as an FRS respondent beginning with the 1989 reporting year.

In 1989, the FRS companies' net income from the nonenergy line of business declined 16 percent (Table 3). However, for operations which were ongoing in both 1988 and 1989, the decline is overstated due to divestiture activity in 1989. Operating income[10] from chemical businesses declined from $12.7 billion in 1988 to $11.3 billion in 1989, or by 11 percent (Table 4). Absent from operating income in 1989 were ARCO's Lyondell Petrochemical subsidiary, which ARCO carried as an investment rather than as a consolidated subsidiary in 1989, and Tenneco's chemical operations, Tenneco having been dropped as an FRS respondent in 1989 subsequent to the divestiture of their petroleum operations in 1988. Excluding the operating income of Lyondell and Tenneco yields a decline in the FRS companies' income from ongoing chemical operations of 3 percent between 1988 and 1989. The decline was a reflection of lessened demand growth and higher operating costs. Excluding Lyondell and Tenneco, revenues grew by only 2 percent between 1988 and 1989. Operating costs were 4 percent higher due to increased oil and feedstock prices.

Figure 5. Revenues and Operating Expenses for the Chemical Segment for FRS Companies, 1981-1989



Source: 1981–1986: Energy Information Administration, Form EIA-28. 1987 through 1989 company annual reports to shareholders.

Table 4. Operating Income and Operating Rate of Return in the Chemicals and Other Nonenergy Segments for FRS Companies, 1985-1989

Segment	1985	1986	1987	1988	1989	Percent Change 1988-1989
	(million dollars)					
Operating Income, Excluding Unusual Items						
Chemicals	2,495	5,057	8,231	12,666	11,311	-10.7
Other Nonenergy	587	2,174	2,173	2,788	1,713	-38.6
	(percent)					
Operating Rate of Return[a]						
Chemicals	12.5	24.2	37.2	49.3	39.6	--
Other Nonenergy	1.8	7.9	7.1	11.8	9.6	--

[a]Operating income (excluding unusual items) divided by net property, plant, and equipment.

-- = Not applicable.

Source: Energy Information Administration, Form EIA-28, except for chemicals segment operating income for 1987 through 1989 which was compiled from company annual reports to shareholders.

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[10] For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, the comparable disclosures in the Form EIA-28 from 1981 through 1986. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 1989. Revenues and operating income for the other nonenergy segment after the 1986 reporting year were obtained by subtracting the publicly disclosed chemical segment values from the nonenergy line-of-business values reported on Form EIA-28. It should be noted that the results for chemicals are qualitatively unchanged if Du Pont is excluded.

The diversified businesses of the FRS companies registered a 39-percent decline in operating income between 1988 and 1989. In addition to Lyondell and Tenneco, the 1989 results also exclude significant divestitures by USX (a large nonenergy mining subsidiary in Canada and a large steel-making complex), Burlington Resources (forest products businesses), and Coastal (ANR Freight subsidiary). Excluding these companies, operating income from other nonenergy businesses was $1.2 billion in both 1988 and 1989. That is, for FRS companies' diversified businesses that essentially remained intact in 1988 and 1989, income was unchanged.

Despite the reported declines in nonenergy income, the level of profitability of chemical operations and nonenergy businesses in 1989 was second only to 1988 in the context of the 1980's.

Non-operating Factors and Change in Earnings

About 40 percent of the change in the FRS companies' net income between 1988 and 1989 was due to reduced income from continuing operations (Table 5). The remainder came from the combination of unusual items of a non-recurring nature and changes in income tax rates.

In 1989, FRS companies' net income from discontinued operations totaled $233 million, down from $1,344 million in 1988. The decline in this category of income accounted for 44 percent of the change in overall net income. Nearly all of the drop in income from discontinued operations was a result of Tenneco's sale of their petroleum assets in 1988. Excluding Tenneco, income from discontinued operations hardly changed between 1988 and 1989.

The change in the FRS companies' overall effective tax rate (income tax expense divided by pretax income) contributed to the decline in their bottom-line net income in 1989. The effective tax rate rose from 39.4 percent in 1988 to 40.3 percent in 1989 (see Chapter 3 for a more detailed discussion of taxes). This increase was primarily the result of a shift in the composition of pretax income toward the foreign oil and gas production segment which has the highest effective tax rate among FRS lines of business. Also, the effective tax rate in foreign oil and gas production rose slightly due to a shift in FRS foreign oil production to the higher tax jurisdictions of the Middle East, Other Eastern Hemisphere, and Africa. By contrast, a reduction in the FRS companies' overall effective tax rate, from 55.1 percent to 39.4 percent, contributed substantially to the increase in the FRS companies' net income in 1988. A reduction in the U.S. Federal corporate income tax rate from 40 percent in 1987 to 34 percent in 1988 and reductions in tax rates in some foreign countries primarily accounted for the reduction in the overall effective tax rate.

Other non-operating items, on balance, had little effect on the decline in the FRS companies' net income between 1988 and 1989. These items totaled a negative $1.2 billion in 1988 and a negative $1.1 billion in 1989.

Table 5. Sources of Change in Net Income for FRS Companies, 1988 and 1989

Source	1988	1989
	(million dollars)	
After-Tax Operating Results[a]	2,933	-1,013
Reduction in Effective Tax Rates[b]	3,009	-513
Discontinued Operations	1,367	-1,111
Other Unusual Items	3,773	82
Total Change in Net Income	11,082	-2,555

[a] Assumes 1987 effective tax rate for 1988 and 1988 effective tax rate for 1989. Excludes unusual items.

[b] Difference between income tax expense computed at prior year's effective tax rate and reported income tax expense. Excludes unusual items.

Source: Energy Information Administration, Form EIA-28 and company annual reports to shareholders.

Targets of Investment

The lower oil prices of the 1986 through 1989 period had a number of effects on the investment targets of the FRS companies. Investment in U.S. oil and gas production has been hit hardest by lower oil prices. The profitability of prospective U.S. oil and gas investments was reduced by lower oil prices. Further, within the FRS companies' worldwide oil and gas operations, the profitability of U.S. operations has been more impaired than has the profitability of foreign operations (Chapter 6, Figure 28). Consequently, the share of the FRS companies' total investment allocated to U.S. oil and gas operations declined from nearly 50 percent in the 1981 through 1985 period to less than one-third in the 1986 through 1989 period, while, between the same periods, the share for foreign oil and gas production increased from 16 percent to 21 percent. The shift in the FRS companies' investment has been to the areas with increased profitability in recent years: refining, marketing, and chemicals. Over the 1981 through 1985 period, the share of the FRS companies' investment allocated to refining and marketing ranged from 11 percent to 15 percent. This share increased to 17 percent in 1986 and has been at 20 percent in each of the last three years. For chemical operations, the share averaged 7 percent for 1981 through 1985, rose to 11 percent in 1986 and 1987, and rose again to 14 percent in 1988 and 1989.

Overall Capital Expenditures Fall Due to Reduced Merger and Acquisition Activity

Total capital expenditures of the FRS companies in 1989 declined 9 percent from 1988 expenditures, to $45.0 billion (Table 6).[11] Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures were up 4 percent, to $35.3 billion, the highest level since 1985 (Figure 6).[12]

Capital expenditures related to mergers and acquisitions were $9.7 billion in 1989, $6.2 billion less than in 1988. The bulge in merger and acquisition activity in 1988, compared with 1989, was largely the result of Tenneco's sale of their petroleum assets in 1988, from which they realized nearly $8 billion in gross proceeds. Various FRS companies spent a total of $5.4 billion for acquisitions of Tenneco's assets in 1988.

In 1989, the largest acquisition by an FRS company was Exxon's purchase of Texaco Canada for $4.2 billion (Table 7). The sale of Texaco Canada was part of Texaco's restructuring program aimed at increasing shareholder value. Texaco utilized the proceeds to pay special dividends of $1.9 billion, reduce debt, and initiate a stock repurchase program. The bulk of the value of FRS acquisitions in 1989 were for oil and gas production assets, as was true in 1987 and 1988 (Table 8). Acquisitions in oil and gas production accounted for 71 percent of the FRS companies' capital expenditures related to mergers and acquisitions in 1989.

The FRS companies also make capital expenditures for environmental protection purposes. Until 1989, too few companies disclosed these expenditures to permit a meaningful review. However, in 1989, 17 FRS companies disclosed expenditures for environmental protection and 14 of these companies separately disclosed capital expenditures. For these 14 companies, environmentally-related capital expenditures totaled $1.6 billion which was equal to 7.8 percent of their expenditures for property, plant, and equipment, excluding mergers and acquisitions. Planned 1990 capital expenditures for environmental protection are 58 percent greater than 1989 expenditures for the eleven companies making this disclosure.

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[11] To the extent possible, capital outlays are measured by additions to investment in place, which are defined as additions to property, plant, and equipment (PP&E) plus additions to investments and advances. In 1989, additions to PP&E accounted for 96.7 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, capital outlays are sometimes measured by additions to PP&E. Also, in comparisons with the S&P 400, this latter measure is used since the S&P 400 data base does not provide an item comparable to additions to investment and advances.

[12] Figure 6 and Table 8 show the value of PP&E and investments and advances added to the companies' books as a result of acquisitions rather than the value of the transactions. The reported, or purchase, value of an acquisition shown in Table 7 can include effects on working capital, long-term liabilities, and other values which would not add to the acquiring company's investment base.

Table 6. Additions to Investment in Place by Line of Business for FRS Companies, 1987-1989
(Billion Dollars)

Line of Business	1987	1988	1989	Percent Change 1988-1989	Percent Change Excluding Mergers and Acquisitions 1988-1989
Petroleum					
U.S. Petroleum					
Production	11.3	17.8	11.9	-33.0	-16.5
Refining/Marketing					
Refining	1.9	3.7	2.4	-34.1	NA
Marketing	2.1	2.8	2.8	-0.3	NA
Transport	0.4	0.3	0.3	13.3	NA
Total Refining/Marketing	4.5	6.8	5.5	-18.1	-5.8
Pipelines	0.9	0.7	0.7	-2.8	2.1
Total U.S. Petroleum	16.7	25.3	18.2	-28.2	-12.5
Foreign Petroleum					
Production	7.4	10.3	12.4	20.8	34.2
Refining/Marketing	2.4	3.3	3.4	0.9	-43.8
International Marine	0.1	0.2	0.2	43.7	43.7
Total Foreign Petroleum	9.9	13.7	16.0	16.2	11.4
Total Petroleum	26.6	39.1	34.2	-12.5	-4.7
Coal	0.6	0.6	1.0	81.6	46.3
Other Energy					
U.S.	0.2	0.2	0.1	-63.8	NA
Foreign	0.1	0.2	0.1	-56.3	NA
Total Other Energy	0.3	0.4	0.2	-59.8	-58.7
Nonenergy					
Chemicals	3.8	7.2	6.3	-12.6	22.9
Other Nonenergy	2.9	2.4	2.4	0.5	36.9
Total Nonenergy	6.7	9.7	8.8	-9.3	20.6
Nontraceables	0.6	0.0	0.9	--	--
Additions to Investment in Place[a]	34.8	49.7	45.0	-9.4	--
Additions Due to Mergers and Acquisitions	5.9	15.8	9.7	-39.1	--
Total Additions Excluding Mergers and Acquisitions	28.9	33.8	35.3	4.5	--

[a] Measured as additions to PP&E plus additions to investments and advances.

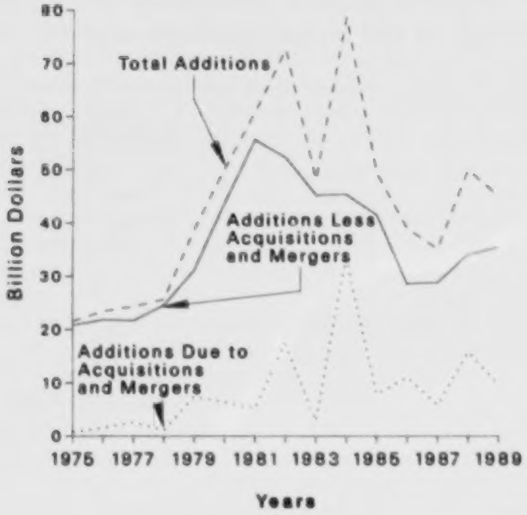
NA = Not available.

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Figure 6. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1975-1989



Sources: Energy Information Administration, Form EIA-28, and company filings of Securities and Exchange Commission Form 10K.

Line-of-Business Investment Patterns

Foreign Oil and Gas Became Primary Investment Target in 1989. Oil and gas production accounted for the majority of FRS companies' capital expenditures in 1989. Expenditures for oil and gas production were primarily for exploration and development. In the United States, capital expenditures declined nearly $6 billion, to $11.9 billion (Table 6). About two-thirds of the decline came from reduced expenditures for acreage. In 1988, expenditures for unproved acreage were relatively high largely due to a record level of offerings of Federal Outer Continental Shelf (OCS) tracts for lease, an event which was not repeated in 1989. The Tenneco divestiture in 1988 led to a substantial increase in the FRS companies' expenditures for U.S. proved acreage. In 1989, there were no sales of U.S. oil and gas assets comparable to the Tenneco divestiture. The low level of oil prices, subsequent to the oil price crash of early 1986, has discouraged oil drilling in the United States even though U.S. crude oil prices rose by over $3 per barrel between 1988 and 1989. The FRS companies' capitalized drilling expenditures in the United States declined $0.7 billion between 1988 and 1989. Well completions (excluding exploratory dry holes) fell 18 percent and unit drilling costs were up 5 percent. Oil drilling led the decline, with FRS oil well completions falling 29 percent. By contrast, natural gas well completions continued on an upward trend, which began in 1988, rising 15 percent in 1989. Increased natural gas demand together with more optimistic expectations for future demand stemming from environmental considerations appeared to more than offset the effects of flat year-to-year prices.

For the first time during the 1974 through 1989 period of FRS data collection, foreign oil and gas capital expenditures exceeded U.S. expenditures. Abroad, the FRS companies' capital expenditures for oil and gas production were $12.4 billion in 1989, a 21-percent increase from 1988. The categories of expenditures registering most of the increase were lease equipment and development drilling. Most of the heightened level of equipment expenditures reflected a steam flood project in Indonesia and installation of improved recovery programs in maturing fields in the North Sea. Although the FRS companies' overall foreign development drilling was down sharply in 1989, the decline was almost wholly concentrated in Canada. Apart from Canada, development well completions were up 3 percent. Among foreign regions, expenditures increased the most for the Other Eastern Hemisphere and mainly reflected spending for projects in support of supplying liquified gas to Pacific Rim industrial centers and a variety of other development projects in Malaysia and Indonesia.

Marketing Expenditures Maintained at Record Level. The improved profitability of U.S. refining and marketing in recent years has led to a modest upturn in the attractiveness of these operations as an investment target for the FRS companies. Although capital expenditures for U.S. refining and marketing were down 18 percent between 1988 and 1989, the decrease was related to reduced merger and acquisition activity and, to a lesser extent, the effects of Texaco's formation of the Star Enterprise joint venture with Saudi Arabia.[13] Apart from these developments, the FRS companies' capital expenditures for U.S. refining and marketing increased by $0.5 billion, to $5.2 billion.

In 1989, capital expenditures for petroleum marketing about matched the record expenditures of $2.8 billion in 1988. Marketing has become an investment target in recent years after many years as an area of net retrenchment. Increased petroleum consumption, due to lower petroleum prices subsequent to the oil price crash of 1986, created opportunities for growth and investment. During this period, the FRS companies placed strategic emphasis on their own marketing outlets. Between 1985 and 1989, the number of FRS company-operated gasoline outlets rose 17 percent and accounted for 49 percent of the growth in their gasoline sales volumes.

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[13] In their *1988 Annual Report*, Texaco reported $852 million in additions to investments and advances to unconsolidated subsidiaries for the formation of the Star Enterprise joint venture.

Table 7. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1989
(Million Dollars)

Line of Business and Acquiring Company	Acquisition	Reported Value
Oil and Gas Production		
Exxon	Texaco Canada	4,150
Amerada Hess	TXP's U.S. oil and gas properties	866
Texaco	Tana Production Corporation	476
Amerada Hess	37-percent interest in Texas Eastern U.K. oil and gas subsidiary	267
Exxon	Various U.S. oil and gas interests from Occidental Petroleum	148
Kerr-McGee	Maxus Energy Canada, Ltd.	141
Du Pont	U.S. gas processing plants from Enerfin Partners	135
Chevron	Beaufort Sea Holdings from Husky Oil	123
Du Pont	Interests in U.S. producing properties from Transco Energy	115
Sun	5-percent interest in the U.K. Magnus Field	87
Exxon	Tenneco's Williston Basin properties	55
Occidental Petroleum	77.5-percent interest in Smackover (Texas) gas processing plant	39
Coastal	U.S. producing wells from Total Petroleum	22
Du Pont	U.S. oil and gas properties from Total Petroleum	22
Refining/Marketing		
Total Petroleum (North America)	106 Road Runner service stations	109
Coastal	Aruba refinery (shut down)	8
Coal		
Coastal	Howell Corporation's coal mining and marketing unit	7
Nonenergy		
Du Pont	Howson Algraphy and Crosfield Electronics (prepress business)	611
Union Pacific	Preferred stock (convertible to 25-percent equity interest) of company which acquired the Chicago and Northwestern railroad	100
Ashland Oil	66 7-11 stores plus other nonenergy businesses	61
Sun	Eaton Credit Corporation	33

Source: Company annual reports to shareholders, *Oil and Gas Investor* (April and August 1990), and various issues of *The Wall Street Journal*.

Table 8. Line-of-Business Distribution of Additions to Investment in Place Associated With FRS Mergers and Acquisitions, 1987-1989

Line of Business	Value 1987	Value 1988	Value 1989	Distribution 1987	Distribution 1988	Distribution 1989
	(million dollars)			(percent)		
Oil and Gas Production	4,190	10,749	6,887	70.7	67.8	71.3
Refining, Marketing, and Transport	803	2,080	2,272	13.5	13.1	23.5
Coal and Other Energy	0	79	232	0.0	0.5	2.4
Chemicals	204	2,211	153	3.4	14.0	1.6
Other Nonenergy	730	727	112	12.3	4.6	1.2
Total	5,927	15,846	9,656	100.0	100.0	100.0

Note: Sum of components may not equal total due to independent rounding.
Sources: Energy Information Administration, Form EIA-28 and Securities and Exchange Commission Form 10K.

Massive divestitures of foreign downstream assets were undertaken by the FRS companies in the 1980 through 1985 period. Their foreign refining capacity was reduced by 3 million barrels per day over this period. Since 1986, the FRS companies' foreign refining capacity has declined by only 3 percent. Foreign refining and marketing, outside of Canada, continued to be an area of modest retrenchment in 1989. Sales of refining and marketing assets outside of the United States were reported by Chevron, Mobil, and Texaco in 1989. Amoco prepared to sell downstream assets in the United Kingdom in a transaction which was consummated in 1990. The FRS companies' capital expenditures for refining and marketing of $3.4 billion in 1989 were little changed from 1988. However, excluding the effect of mergers and acquisitions, most of which was related to Exxon's acquisition of Texaco Canada in 1989, capital expenditures declined 43 percent.

Energy operations outside of petroleum accounted for less than 3 percent of the FRS companies' total capital expenditures in 1989. Nevertheless, the FRS companies are significant players in some non-petroleum energy areas. For example, the FRS companies accounted for 29 percent of U.S. coal production in 1989. In coal operations, capital expenditures rose sharply from the prior year, to $1.1 billion, the highest level since 1985. Over two-thirds of the increase in capital expenditures was for foreign coal operations. ARCO and Exxon reported sizable acquisitions of Australian coal properties in 1989. In the United States, the FRS companies' capital expenditures for coal operations increased 33 percent, to $0.6 billion. The expenditures appeared to be related to cost-reducing improvements at existing facilities in that the FRS companies' U.S. coal production capacity rose only 3 percent and their production increased only 1 percent between 1988 and 1989.

Chemical Profitability Attracts Investment. Chemical businesses have been a source of growth and increased profitability for FRS companies since 1986 (Figure 5 and Table 4). Accordingly, their capital expenditures for these businesses have increased in recent years. The $6.3 billion in capital expenditures in 1989 was second only to 1988's expenditures over the 1974 through 1989 period of FRS data collection. Apart from the effect of mergers and acquisitions (such as Occidental Petroleum's acquisition of Cain Chemical Corporation for $2.2 billion in 1988), the FRS companies' capital expenditures were up 23 percent between 1988 and 1989 (Table 6), with over three-quarters of the companies reporting an increase.

Somewhat in contrast has been the FRS companies' experience in diversified businesses outside of energy and chemicals. Increased profitability in this area has largely been achieved through divestiture of businesses that were insufficiently profitable or otherwise not integral to long-term investment strategies. As a result of this strategy, 1989 capital expenditures for the other nonenergy line of business of $2.4 billion, though up from 1988, remained at a historically low level for the decade.

Sources and Uses of Cash

Income, investment, and profitability are essential measures of financial performance. Also of importance in assessing changes in the financial health of a company or industry is the composition of capital sources and capital deployment. In previous editions of this report, the statement of sources and uses of funds was utilized to review patterns of financing and expenditure. Beginning with the 1988 reporting year, the Financial Accounting Standards Board required adoption of the Statement of Cash Flows to replace the sources and uses format and most companies restated their results for 1986 and 1987 in this new format.

Sources of Cash

The primary source of cash[14] is cash flow from operations.[15] In 1989, the FRS companies' cash flow from operations totaled $48.3 billion, down slightly from $48.4 billion in 1988 (Table 9). Among the lines of business, the contribution (before taxes) from oil and gas production increased $2.6 billion as a result of the favorable effects of higher oil prices (Table 10). This gain in cash flow was more than offset by reduced cash flow from downstream petroleum operations, chemical businesses, and other nonenergy activities. Current taxes, which are income taxes deemed payable in the reporting year, were up slightly, reducing cash flow by $0.6 billion.

Other items, on balance, contributed $4.7 billion to the change in cash flow between 1988 and 1989. The category "Other (Net)," shown in Table 10, contains many diverse items. Many of these items are essentially adjustments to remove non-cash components recognized in the income statement and to recognize actual expense (or revenue) in the year of incurrence. For example, suppose a company, in 1989, set up a reserve of $20 million to pay for environmental clean-up costs, both in 1989 and in the future, and recognized the establishment of this liability by taking a $20 million charge against income in 1989. However, if only $10 million of the reserve was actually spent in 1989, then the remaining $10 million is added back in order to measure actual cash flow. Similarly, if the remaining $10 million is expended in 1990, then $10 million would be subtracted in computing cash flow from operations in 1990. The $4.7 billion change in the value of other items shown in Table 10, between 1988 and 1989, is largely traceable to two developments that occurred in 1988: Texaco's payment of $3 billion for a litigation settlement (provisions for the settlement were recognized by Texaco in their 1987 income statement) and the negative effect on cash flow from operations stemming from Tenneco's sale of their petroleum assets.

Long-term debt is the most important source of external funding, ranking second to cash flow from operations as a source of cash. In 1989, proceeds from long-term debt offerings totaled $20.7 billion, which was not much different from the 1987 and 1988 values (Table 9). This latter trend was in contrast to the 1984 through 1986 period when mergers, restructuring, and takeover defenses were prominent among the FRS companies. During the 1984 through 1986 period, annual proceeds from long-term debt averaged $30.4 billion. Since then, most FRS companies have taken measures to reduce their debt. In 1989, only two FRS companies reported large increases in long-term borrowing: Exxon, whose proceeds from long-term debt increased by $3.8 billion, between 1988 and 1989, in connection with their acquisition of Texaco Canada, and Du Pont, whose borrowings increased $2.4 billion for repurchases of common stock and acquisitions. Among the remaining FRS companies, a majority reported a reduction in proceeds from long-term debt.

Sales of assets were a much more important source of cash in 1988 and 1989 than in the prior two years. This development was in large part a reflection of the restructuring efforts by some FRS companies. Additionally, the FRS companies have sought to contain the growth in debt financing by utilizing other means of raising funds, including asset sales. Asset sales by the FRS companies yielded $13.2 billion in proceeds in 1989, down from the peak value of $16.0 billion in 1988. In 1988, Tenneco reported $7.4 billion from the sales of their petroleum assets, most of which were purchased by other FRS companies. Other companies with large asset sales in that year included Mobil, who sold Montgomery Ward and other assets for $2.5 billion, and Texaco, who realized $1.6 billion largely from the sale of foreign petroleum assets. In 1989, Texaco reported $4.8 billion from asset sales, mainly from the sale of Texaco Canada to Exxon, and BP America sold their nonenergy mineral operations for $2.8 billion.

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[14] Cash is defined as currency, demand deposits, and interest-bearing assets of less than 30 days maturity.

[15] Generally, cash flow from operations is computed by adding to (subtracting from) net income those cost (revenue) items which did not actually involve an outlay (receipt) of cash. The largest of these non-cash items is the cost of depreciation, depletion, and amortization (DD&A). Also, outlays (receipts) of cash which were recognized as non-cash items in previous income statements (e.g., provision for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.

Table 9. Statement of Cash Flows for FRS Companies, 1986-1989
(Billion Dollars)

Items Providing /(Using) Cash[a]	1986	1987	1988	1989
Cash Flow from Operations				
Net Income	9.2	11.3	22.3	19.8
DD&A	31.2	30.7	31.1	29.6
Deferred Income Taxes	3.8	0.8	1.3	0.2
Other Items, Net	0.0	4.4	-6.2	-1.3
Net Cash Flow from Operations	44.2	47.1	48.4	48.3
Cash Flow from Investing Activities				
Additions to Investment in Place	-39.7	-34.8	-49.7	-45.0
Proceeds from Disposals of Assets	11.2	6.4	16.0	13.2
Other Investment Activites, Net	2.7	-5.3	4.6	-2.0
Net Cash Flow from Investing Activities	-25.8	-33.8	-29.1	-33.8
Cash Flow from Financing Activities				
Proceeds from Long-term Debt	30.4	19.7	19.3	20.7
Proceeds from Equity Security Offerings	5.0	2.3	2.7	4.2
Reductions in Long-term Debt	-30.1	-20.2	-28.8	-19.8
Purchase of Treasury Stock	-2.8	-3.8	-6.6	-6.2
Dividends to Shareholders	-11.3	-10.6	-12.4	-16.7
Other Financing Activities, Net[b]	-4.4	-2.0	0.2	1.8
Net Cash Flow from Financing Activities[b]	-13.1	-14.6	-25.7	-16.0
Net Change in Cash and Cash Equivalents	5.2	-1.3	-6.3	-1.5

[a] Items that provide cash are positive and items that use cash are shown as negative values.
[b] Includes effects of exchange rate changes on cash.
Note: Sum of components may not equal total due to independent rounding..
Sources: 1989: Form EIA-28, 1986-1988: Form EIA-28 and company annual reports to shareholders.

Table 10. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1986-1989
(Million Dollars)

Contribution to Pretax Cash Flow[a]	1986	1987	1988	1989
Petroleum				
Oil and Gas Production	33,589	41,567	33,446	36,089
Refining, Marketing, and Transport	17,001	10,913	19,296	15,517
Coal and Other Energy	590	1,274	1,367	1,406
Nonenergy	9,417	14,657	19,441	16,921
Nontraceable	-1,927	-2,211	-1,516	-2,194
Total Contribution to Pretax Cash Flow[a]	58,670	66,200	72,034	67,739
Current Income Taxes	-6,712	-13,009	-12,217	-12,796
Other (Net)	-7,764	-6,049	-11,390	-6,659
Cash Flow from Operations	44,194	47,142	48,427	48,284

[a] Defined as the sum of operating income, DD&A, and dry hole expense.
Source: Energy Information Administration, Form EIA-28.

Texaco's asset sales were part of their restructuring program subsequent to emerging from Chapter 11 bankruptcy. They utilized the proceeds to reduce debt, pay special dividends, and initiate a stock repurchase program in order to increase shareholder value. BP America's parent corporation, British Petroleum, reported that the sale of their mineral operations contributed to the purchase and retirement of British Petroleum shares owned by Kuwaiti investors.

Uses of Cash

The mega-mergers among FRS companies, in 1982 and 1984,[16] and costly takeover defenses, particularly in 1985, led to high levels of long-term debt. One often-used measure of the importance of debt in companies' balance sheets is the ratio of long-term debt to stockholders' equity. Between 1981, the year prior to increased merger and acquisition activity, and 1985, the FRS companies' debt-equity ratio rose sharply, from 32 percent to 54 percent. The ratio edged up a bit, to 58 percent, in 1987 and has since declined slightly, to 56 percent in 1989. The growth in debt has resulted in substantially greater outlays for reductions in long-term debt. For years prior to 1982, FRS companies' outlays for long-term debt reduction never exceeded $8 billion, between 1982 and 1984 annual debt repayment averaged $13 billion, and since 1985, outlays for long-term debt reduction ranged from a high of $30 billion in 1986 to $20 billion in 1987 and 1989. In part, this development reflected the fact that there was simply more debt to repay. More importantly, most of the FRS companies have sought to contain the growth in their debt, as evidenced by the stability of their debt-equity ratio in recent years.

In addition to restructuring and debt reduction, the FRS companies have sought to increase shareholder value through increased dividend payments and purchase of their own common stock in recent years. Dividend payments rose by over $4 billion between 1988 and 1989, to $16.7 billion, following a nearly $2 billion increase in the prior year. A large part of the increase in dividends was Texaco's payment of special dividends of $1.9 billion as part of their restructuring. The balance of the increase reflected increased dividend payments by 21 of the 23 FRS companies. By purchasing its own stock, a company will tend to raise its market value and the wealth of its shareholders. In 1989, two-thirds of the FRS companies repurchased their stock for a total outlay of $6.2 billion, down slightly from outlays of $6.6 billion in 1988.

Update on Restructuring

Restructuring, which is a multifaceted process, has as its purpose the improvement of corporate profitability and returns to stockholders. The most intense period of restructuring for the FRS companies was 1984 through 1986. In response to declining oil prices, most FRS companies pursued a number of strategies to improve their overall profitability and increase their shareholders' wealth. These measures included mergers and acquisitions, divestiture of businesses (particularly outside of petroleum), workforce reductions, and stock repurchase programs.[17] Much debt was accumulated during this period. Restructuring resulted in large charges against net income as well. Major restructuring efforts have been less frequent in recent years. Texaco reported large charges against income for restructuring in 1987. In 1988 and 1989, no FRS company reported charges in excess of $0.5 billion for restructuring. However, large charges against income related to environmental matters were incurred in 1989. A number of companies made substantial provisions in 1989 for environmental clean-up costs which were recognized as charges against income and some FRS companies had substantial writedowns of offshore California properties due to a change in state regulations which was related to environmental considerations.

Nevertheless, a majority of companies continued to report divestitures of businesses, assets, and sales of ownership interests in 1989 (Table 11). Divestitures which exceeded $1 billion in value included Texaco's sale of Texaco Canada, from which Texaco reported $3.8 billion in proceeds, and BP America's sale of its nonenergy minerals businesses for $2.8 billion. A more recent trend with respect to asset deployment has been the sale of equity interests in subsidiaries. In 1989, transactions that involved the sale of partial ownership interests included:

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[16] In late 1981, Du Pont acquired Conoco (an FRS respondent) which, for FRS purposes, was treated as occurring on January 1, 1982. In 1982, USX (formerly U.S. Steel) acquired Marathon Oil (an FRS respondent) and two FRS respondents, Occidental Petroleum and Cities Service, merged. Intra-FRS mergers in 1984 included Chevron-Gulf, Mobil-Superior Oil, and, Texaco-Getty Oil. The value of these mergers totaled $47.0 billion.

[17] Developments related to the FRS companies' restructuring in the 1984 through 1986 period were extensively reviewed in Energy Information Administration, *Performance Profiles of Major Energy Producers 1985*, DOE/EIA-0206(85) (Washington, DC, January 1987) and Energy Information Administration, *Performance Profiles of Major Energy Producers 1986*, DOE/EIA-0206(86) (Washington, DC, January 1988).

Table 11. Asset Disposals of FRS Companies, 1989

Company	Asset Disposal
Amoco	Shares of Placer Dome (Canada), Williston basin oil and gas properties, and oil and gas properties in Canada.
Ashland Oil	Carbon black operations.
Atlantic Richfield	Public offering of common shares of Lyondell Petrochemical Company.
BP America	Nonenergy minerals business and royalty trust related to Prudhoe Bay (AK) production.
Burlington Resources	Public offering of limited partnership units in Plum Creek Timber Company.
Coastal Corporation	Investment in Texas Eastern Corporation, ANR Freight (trucking)
Du Pont	Interest in U.K. Victor Field (North Sea).
Exxon	Branch office facility in Japan.
Mobil	South African operations, Hong Kong Terminal, California real estate development, interest in Octel Associates.
Occidental Petroleum	Powder River Basin (Wyoming) oil and gas properties (to Exxon).
Oryx Energy	Interests in U.S. oil and gas properties in 12 States (to American Exploration Company).
Sun	Interest in a high-rise office building.
Texaco	Texaco Canada (to Exxon subsidiary, Imperial Oil), Swedish marketing subsidiary, and Four Star Oil and Gas Company (to Mission Energy Oil and Gas Company).
Unocal	Transferred Illinois refinery and related assets to Uno-Ven (a joint venture with Petroleos de Venezuela), sold coal operations in Western Canada, and California real estate.
USX	Quebec Cartier Mining Company (to DoFasco Inc.), U.S. Agri-Chemicals (to Sinochem American Holdings, Inc.), Lorain Works (to joint venture with Icobe Steel, Ltd.), remaining interests in South African companies, and 5 tankers.

Source: Company annual reports to shareholders and *Oil and Gas Investor* (April and August 1990).

- ARCO, through a public offering of common stock, sold 50.1 percent of its interest in its Lyondell Petrochemical subsidiary for $1,241 million;
- Burlington Resources sold partnership shares in its Plum Creek Timber subsidiary, for $615 million, converting the subsidiary to a limited partnership and retaining an 11-percent interest;
- BP America sold units in a royalty trust related to its Alaskan Prudhoe Bay oil field, for $514 million, in which the units earn 16.4 percent of the net profits interest in the first 90 thousand barrels per day of production;
- Unocal transferred its Illinois refinery (147 thousand barrels per day crude distillation capacity) and related marketing assets to Uno-Ven, a 50-50 joint partnership with Petroleos de Venezuela, a transaction which had a value of $500 million to Unocal; and
- Coastal Corporation transferred its California refinery to Pacific Refining, a 50-50 joint venture with Sinochem, an affiliate of the Peoples' Republic of China (no value reported).

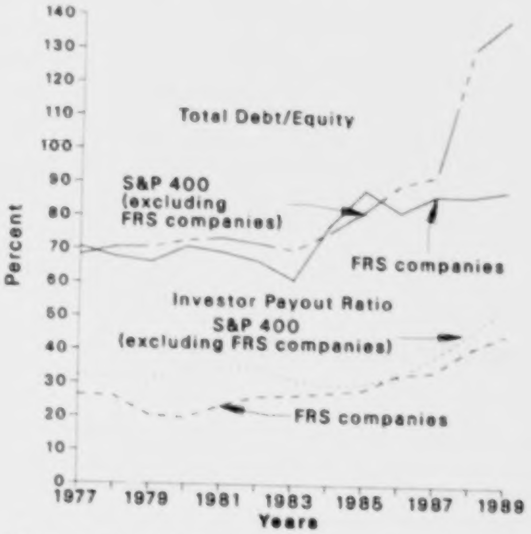
Similar sales of ownership interests in 1988 included Texaco's 50-50 refining/marketing joint venture (Star Enterprise) with Saudi Arabian interests and involved transfer of 615 thousand barrels per day of refining capacity and associated marketing assets from Texaco to the joint venture, and, in 1987, ARCO made a public offering of 19.5 percent of the stock of ARCO Chemical Company, Occidental Petroleum made a similar offering of 49 percent of their IBP agribusiness subsidiary, and Union Pacific and Petroleos de Venezuela formed a 50-50 refining joint venture (in 1988, Petroleos de Venezuela gained 100-percent ownership). Sales of equity interests can have the advantages to the parent company of raising funds without resorting to debt financing and retaining effective control of the management of the business.

Finanical Structure and Investor Perceptions

Reducing the rate of growth in debt has been one of the objectives of most of the FRS companies' restructuring efforts. Overall, this objective has been largely met in recent years. Figure 7 shows the ratio of total debt (long-term debt, notes payable, and accounts payable) to stockholders' equity. For the FRS companies, the ratio has changed little since 1985, indicating that debt has grown at about the same rate as the (book) value of ownership. Other industrial companies, as represented by the S&P 400 (excluding the FRS companies), by contrast, have shown substantial growth in debt since 1985.[18] The higher levels of debt together with efforts to increase shareholder value through increased dividend payout[19] have resulted in a larger share of cash flow going to investors (Figure 7). Other industrial companies have shown a somewhat steeper rise since 1985 in the investor payout ratio than have the FRS companies, reflecting the former companies' greater rate of debt accumulation in recent years.

How have investors viewed the efforts and performance of the FRS companies, particularly in recent years? One indicator of investor perception is the ratio of market value to book value (total stockholders' equity).[20] Market value is the product of a company's share price and the number of its outstanding shares. A company's current share price reflects investors' expectations of the future profitability of a company viewed at the time of the purchase of the share. Book value reflects the future profitability expected from productive assets at the time the assets were acquired. This ratio is plotted in Figure 8 for the FRS companies and the balance of the S&P 400. The FRS companies' market-to-book ratio plunged with the onset of declining oil prices in early 1981 and the consequent reduction in the FRS companies' expected future profitability. By contrast, other industrial companies benefited from the upswing in stock prices which began somewhat before the end of the 1981-1982 recession. The gap in investor valuation between the two groups of companies generally widened through 1986. However, since 1986, the pattern has reversed, with the FRS companies' market-to-book ratio rising 45 percent between 1986 and 1989 but for the S&P 400 (excluding FRS companies) the ratio increased only 7 percent. The difference in the ratio between the two groups in 1988 and 1989 was of a value typical of the 1974 through 1978 period when rates of return of the two groups differed little (Figure 3). The market-to-book ratio measure indicates that the investment strategies and restructuring efforts of the FRS companies have apparently improved their standing in the capital markets in recent years.

Figure 7. Debt/Equity and Investor Payout Ratios, 1977-1989



Note: Total Debt/Equity: Total debt (including accounts payable) as a percent of stockholders' equity. Investor Payout Ratio: Cash dividends and after-tax interest expense as a percent of funds from operations (1977–1987) or net cash flow from operations (1988–1989).

Sources: o FRS companies: Energy Information Administration, Form-28. o S&P 400: Standard & Poor's Compustat Services, Inc.

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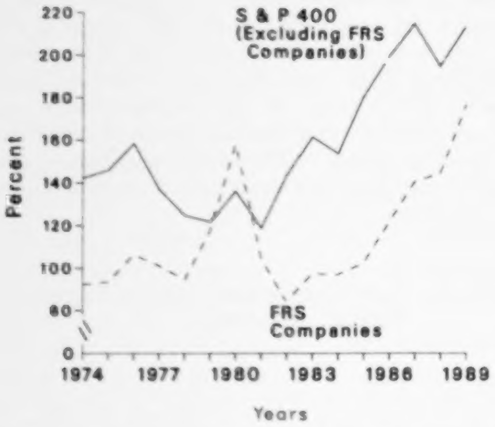
[18] Much of the increase in debt between 1987 and 1988 for the S&P 400 (excluding the FRS companies) was the result of the requirement to adopt Financial Accounting Standard 94, "Consolidation of All Majority-owned Subsidiaries," for the 1988 reporting year. In particular, some manufacturing companies, such as General Motors, have financial subsidiaries with large amounts of assets (e.g., consumer loans) and debt. Prior to 1988, only the parent company's net equity position (an asset item) was recognized in the balance sheet. Beginning in 1988 the large debt and asset positions of financial subsidiaries were separately recognized in the parent company's balance sheet.

[19] An additional factor that may have contributed to increased dividend payments was the Tax Reform Act of 1986 (TRA) which reduced the tax disadvantages of dividend payout relative to retained earnings. The TRA lowered the maximum tax rate on dividends received as individual income and raised the maximum tax rate on long-term capital gains from 20 percent to 28 percent in 1987 and to the same rate as applied to dividends received thereafter.

[20] Ideally, the denominator in the calculation should be total asset replacement value. However, these data are not available. The differentials reported are not likely to differ if the latter data were available. An alternative ratio sometimes use to evaluate oil companies calculates the implied market valuation of proved reserves. Using this ratio would preclude comparison with the S&P 400. An extended discussion of these ratios and their role in mergers can be found in Arthur T. Andersen and T. Crawford Honeycutt, "Management Motives for Takeovers in the Petroleum Industry," *Review of Industrial Organization* (August 1987), pp. 1-12.

Figure 8. Ratio of Market Value to Book Value



Note: Market value is calculated as the year-end common stock price times the number of common shares outstanding. Book value is total stockholders' equity at the end of the year.
Source: Standard & Poor's Compustat Services, Inc.

Diversification Patterns

The investment patterns of the FRS companies together with their restructuring efforts also resulted in greater specialization in petroleum. Beginning with the first oil price escalation of 1973-1974, the FRS companies followed a path of increased diversification. The share of assets for petroleum operations fell steadily, from 81 percent in 1974 to 73 percent in 1983. Thereafter, petroleum businesses received a greater emphasis in investment spending as restructuring efforts intensified. The petroleum share of assets reached 78 percent in 1989, the highest value since 1977. However, within the petroleum line of business, additional shifts occurred. During the 1974-1981 period of rising oil prices, refining and marketing operations were de-emphasized. In large part, this trend reflected the increased profitability and attractiveness of investment in oil and gas production. Additionally, excess refining capacity was becoming a problem due to reduced petroleum consumption, leading to reductions in downstream asset commitments by FRS companies. The U.S. refining industry was left with a large overhang of excess capacity at the beginning of the 1980's largely due to the response of consumers to high oil prices and also because petroleum price regulations were eliminated in 1981. Over the 1981 through 1986 period, 3.2 million barrels per day of U.S. crude oil distillation capacity was eliminated, with the FRS companies accounting for two-thirds of this reduction. However, as petroleum prices generally declined in the first half of the 1980's and then dropped sharply after the oil price crash of 1986, refined product demand (particularly gasoline demand) rose, creating a more favorable financial outlook for downstream petroleum. The lower oil prices of recent years also reduced the profitability of oil and gas production. As a result of these trends, the downstream petroleum share of the FRS companies' net PP&E increased from 20 percent in 1984 to 25 percent in 1989, while, over the same period, the upstream share slipped from a peak of 55 percent in 1984-1985 to 53 percent by 1989 (Table 12).

The increased specialization in petroleum of the FRS companies also reflected a decreased asset commitment to lines of activity outside of energy and chemicals. The escalation of oil prices in the 1970's both increased the cash flow of the FRS companies and, due to reduced petroleum demand, reduced the opportunities for corporate growth through investment in petroleum. Nonenergy diversification became a strategy of many of the FRS companies. The share of assets allocated to diversified businesses rose from 8 percent in 1974 to a peak of 12 percent in 1983. Thereafter, restructuring efforts frequently involved the sale of such assets, with the result that the share of net PP&E for diversified businesses in 1989 was less than half of the 1983 value.

Chemical businesses became a source of increased growth and profitability in recent years. The combination of increased industrial growth and lower feedstock costs contributed to the financial improvement in chemicals. By 1989, chemicals accounted for nearly 10 percent of the FRS companies' investment base, up from the 7 percent share of the mid-1980's.

Table 12. Distribution of Net PP&E by Line of Business for FRS Companies, Selected Years, 1974-1989

Line of Business	1974	1979	1981	1984	1985	1986	1987	1988	1989
	(billion dollars)								
Net PP&E	87.3	159.3	224.9	292.4	297.7	291.1	297.6	293.6	293.4
	(percent)								
Distribution of Net PP&E									
Petroleum									
Oil & Gas Production	39.2	45.1	50.5	55.2	55.3	53.7	52.3	52.9	53.0
Refining/Marketing, Transport	41.7	31.6	25.7	20.2	21.2	23.9	24.2	24.5	25.4
Coal	1.4	2.3	3.0	3.1	2.8	2.7	2.8	2.8	2.8
Nuclear[a]	0.3	0.7	0.6	0.2	0.1	0.1	--	--	--
Other Energy[a]	0.8	1.3	1.3	1.3	1.1	1.0	1.1	1.1	1.1
Nonenergy									
Chemicals	5.7	8.4	7.5	6.9	6.7	7.2	7.4	8.8	9.7
Other Nonenergy	7.9	9.4	10.0	11.4	11.0	9.5	10.2	8.0	6.1
Nontraceables[b]	3.0	1.1	1.4	1.8	1.8	1.9	1.9	1.9	1.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[a] Nuclear and other energy lines of business were combined for FRS reporting purposes beginning with the 1987 reporting year.

[b] Nontraceable revenues, costs, assets, and liabilities cannot be directly attributed to a line of business or cannot be assigned to a line of business by use of reasonable allocation methods based on operating-level realities.

Note: Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, Form EIA-28.

3. Taxation

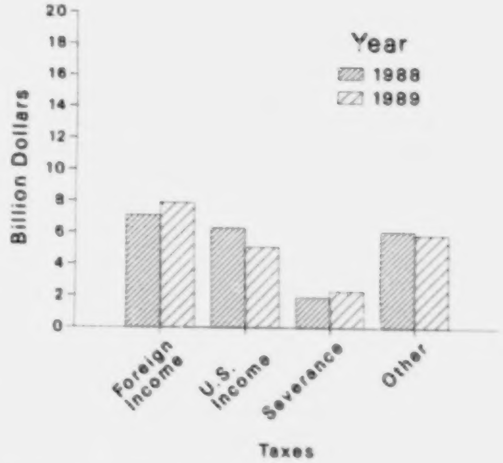
The worldwide annual tax expense of the FRS companies has declined almost continually since the early 1980's.[21] Total taxes for 1989 were less than one-half the level early in the decade. Many factors contributed to the decrease. The most important was the general decline in crude oil prices, which resulted in substantial decreases in pretax income, and therefore in income taxes, in the petroleum production segment. Non-income taxes also fell sharply since some of those taxes are directly dependent on the price of crude oil. These include State severance taxes and the former Windfall Profits Tax.

Changes in foreign and domestic fiscal policies also contributed to the general decline in taxes during the 1980's. Many foreign countries in which FRS companies operate reduced their legislated tax rates on petroleum exploration and development by substantial amounts to encourage additional production in the face of falling prices. Domestically, the Tax Reform Act of 1986 lowered the maximum corporate income tax rate from 46 percent to 34 percent.

As a result of these and other changes, the effective income tax rates (income taxes divided by pretax income) for the worldwide operations of both the FRS companies and U.S. industrial companies in general have shown a downward trend since the mid-1980's. The rates for the two groups of companies were closer to each other in 1989 than at any other time in at least 15 years. The effective rate for the FRS companies, however, continued to exceed that for the more comprehensive group.

Although the tax expenses and effective tax rates for the FRS companies have generally declined, they have also stabilized at historically low levels during the past two years. For example, worldwide tax expense for the FRS companies amounted to $21.2 billion in 1989 (Figure 9), down only $0.2 billion from a year earlier. Although the effective tax rate for consolidated operations rose in 1989 from the prior year, it did so by less than 1 percentage point.

Figure 9. Worldwide Tax Liabilities of FRS Companies, 1988-1989



Note: Excludes foreign taxes other than income taxes.
Source: Energy Information Administration, Form EIA-28.

The high degree of stability in tax expense and effective tax rates from 1988 to 1989 reflects the generally stable business environment during those years as well as foreign and domestic developments that largely offset one another. Specifically, a substantial rise in foreign taxes was somewhat more than offset by a decrease in domestic taxes. The rise in foreign taxes reflects the increased profitability in the petroleum production segment abroad resulting from higher crude oil prices. Although taxes in the domestic production segment rose for the same reason, the increase was more than offset by the effect of higher costs in the refining marketing segment, large increases in tax offsets from special charges (including environmental charges), and a rapid deterioration in business conditions in the nonenergy sector. Increased domestic non-income tax expenses, including increased severance taxes from higher oil prices, were insufficient to offset the decline in U.S. and worldwide taxes.

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[21] Worldwide taxes include both U.S. and foreign income taxes and U.S. non-income taxes. Foreign non-income taxes are not included since they are not collected by the FRS system for all lines of business.

Income Taxes

Overview

Worldwide income tax liabilities (current and deferred) incurred by the FRS companies in 1989 amounted to $13 billion, a decrease of $0.5 billion (or 4 percent) from a year earlier (Table 13).[22] The 4-percent decrease for the FRS companies was in contrast to a 1-percent increase for the S&P 400 group of companies (Table 1). In 1989, the effective income tax rates for the two groups of companies were closer to each other than at any time since at least 1974. The close proximity of the rates and their high degree of stability relative to a year earlier reflected the continued equalizing effects of the Tax Reform Act of 1986. The average domestic rate for the FRS companies fell slightly and the average foreign rate rose to only a small extent.

United States

U.S. income taxes (Federal, State, and local) fell to $5.1 billion in 1989, a decrease of $1.2 billion from a year earlier (Table 13). Taxes for all lines of business that are entirely or largely conducted in the United States fell. Most of the decline was in the nonenergy line of business and in the refining/marketing and pipelines segments of the petroleum sector where profits fell relative to earlier years. Taxes for the petroleum production segment, however, increased sharply. Changes in tax offsets associated with asset writedowns and other special charges also contributed to the overall decline in taxes (Table 14). The contribution of the nonenergy line of business to pretax income and income taxes is reported only on a worldwide basis (Table 15). However, the largest part of this contribution is estimated to be for the United States. Pretax income in the nonenergy sector fell by $1.9 billion, or 12 percent, from 1988 to 1989, and income taxes fell from $5.2 billion to $4.7 billion. These decreases reflect a deterioration in business conditions for that sector, particularly in the chemicals industry. Prior year expansions led to excess capacity and lower product prices in 1989, while increased crude oil feedstock costs contributed to reduced profit margins.

Table 13. Income Tax Expense, Pretax Income, and Tax Shares for FRS Companies, 1985-1989

Taxes and Pretax Income	1985	1986	1987	1988	1989
			(billion dollars)		
Income Taxes					
U.S. Federal	6.5	1.3	4.4	5.5	4.1
U.S. State and Local	0.8	0.5	0.7	0.8	1.0
Foreign	18.0	8.6	8.7	7.1	7.9
Total	25.3	10.5	13.8	13.5	13.0
Worldwide Pretax Income	43.6	20.6	25.0	34.3	32.3
			(percent)		
Distribution of Total Income Taxes					
U.S. Federal	25.7	12.8	32.0	40.8	31.5
U.S. State and Local	3.2	5.0	5.2	6.3	8.0
Foreign	71.1	82.2	62.8	53.0	60.5
Total	100.0	100.0	100.0	100.0	100.0
Income Taxes as a Percent of Worldwide Pretax Income					
U.S. Federal	15.0	6.6	17.6	16.0	12.7
U.S. State and Local	1.9	2.5	2.9	2.5	3.2
Foreign	41.2	42.0	34.6	20.9	24.4
Total	58.0	51.1	55.1	39.4	40.3

Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

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[22] Current income taxes are those incurred and deemed payable during the current period. Deferred taxes, although incurred during the current period, are payable at some future date. See Appendix A for a discussion of deferred taxes.

Table 14. Tax Offsets from Asset Writedowns and Other Special Charges for FRS Companies, 1987-1989
(Million Dollars)

Line of Business	1987	1988	1989
Petroleum			
U.S. Petroleum			
Production	61	-61	493
Refining/Marketing	-31	50	269
Pipelines	156	314	193
Total U.S. Petroleum	186	303	955
Foreign Petroleum			
Production	-3	48	175
Refining/Marketing	-13	0	9
International Marine	0	0	0
Total Foreign Petroleum	-16	48	184
Total Petroleum	170	351	1,139
Coal	29	0	0
Nuclear and Other Energy	19	0	14
Nonenergy			
Chemical	63	84	17
Other	59	17	10
Total Nonenergy	122	101	27
Nontraceables	624	417	29
Total	964	869	1,209

Note: Special charges for which tax offsets were not specified in individual company annual reports were estimated by applying the current U.S. Federal tax rate to those charges.
Source: Company annual reports to shareholders.

Income taxes allocated to the U.S. petroleum line of business fell from $5.3 billion in 1988 to $4.9 billion in 1989 (Table 15). Most of the decrease was in the refining/marketing segment and, to a lesser extent, in the pipelines segment. Pretax income in the refining/marketing segment fell by 24 percent and taxes declined from $2.9 billion to $1.7 billion. The decrease in that segment mainly reflects the effects of higher crude oil prices on operating expenses and a 5-percent fall in refinery output (see Chapter 4). An increase in tax offsets contributed $0.2 billion to the reduction in refining/marketing income taxes. The decrease in income taxes in the pipelines segment also amounted to $0.2 billion. The reduction resulted from a number of developments, including the departure of Tenneco from the FRS reporting system and a 14-percent decrease in pretax income resulting in part from increased competition in pipeline transport.

A sharp increase in income tax expense allocated to the U.S. petroleum production segment was insufficient to offset the combined decrease in the refining/marketing and pipelines segments (Table 15). Taxes in the production segment increased from $1.3 billion in 1988 to $2.2 billion in 1989. The increase was mainly the result of higher crude oil prices, which is reflected in a $2.6 billion increase in operating revenues despite a decline in crude oil and natural gas production. The increase in U.S. petroleum production income taxes would have been greater were it not for large tax offsets resulting from asset writedowns and other special charges. These charges include environmental charges attributable to oil spills and other environmental developments.

The contributions of the nonpetroleum energy lines of business (coal, nuclear, and other energy) to income taxes, like the nonenergy sector, are not reported on a U.S. versus foreign basis. However, the worldwide allocated contributions to these other lines of business fell by less than $0.1 billion from 1988 to 1989 (Table 15). Virtually all of the decrease was for coal, which is almost wholly a U.S. operation. Coal prices fell nationally during 1989 as did the FRS companies' pretax income from coal operations. Only about $1 million of the combined tax decrease for the coal and alternative energy lines of business was for alternative energy. The composition of the alternative energy sector (which incudes nuclear) is no longer reported to the FRS system. Losses continued to be incurred by that sector in 1989 and taxes remained negative.

Table 15. Income Tax Expense and Pretax Income: U.S., Foreign, and Consolidated for FRS Companies by Line of Business, 1988-1989
(Billion Dollars)

Sector	1988 Pretax Income	1988 Income Tax Expense	1989 Pretax Income	1989 Income Tax Expense
Allocated U.S.				
Consolidated Petroleum	14.9	5.3	14.4	4.9
Oil and Gas Production	3.3	1.3	5.3	2.2
Refining/Marketing/Pipelines	11.6	4.0	9.2	2.7
Allocated Foreign				
Consolidated Petroleum	13.4	6.6	14.0	7.2
Oil and Gas Production	9.4	5.1	10.8	6.1
Refining/Marketing/Marine	4.0	1.5	3.1	1.1
Allocated Coal	0.9	0.3	0.8	0.2
Allocated Nuclear and Other Energy	-0.1	-0.1	-0.1	-0.1
Allocated Nonenergy	15.6	5.2	13.7	4.7
Total Allocated	44.6	17.3	42.8	16.9
Nontraceables and Eliminations	-10.3	-3.7	-10.5	-3.9
Total Consolidated	34.3	13.5	32.3	13.0

Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Foreign

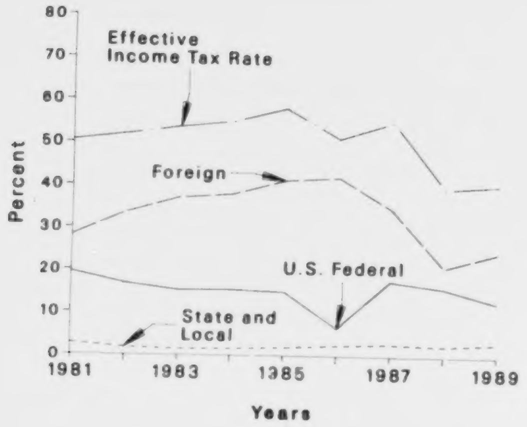
Aggregate foreign income taxes rose to $7.9 billion in 1989, an increase of 10.1 percent, in contrast to the 19 percent fall in the United States (Table 13). Nearly all of the increase in 1989 foreign income taxes resulted from increased taxes in the upstream petroleum line of business. Downstream operations resulted in lower taxes but were swamped by the improved performance and higher taxes upstream.

Allocated income taxes from the foreign petroleum line of business rose to $7.2 billion in 1989, an increase of $0.6 billion from a year earlier (Table 15). The increase in the production segment amounted to $1.0 billion. This was partly offset by a $0.4 billion decrease in taxes in the refining/marketing segment, taxes in the international marine segment being little changed from a year earlier. The increased taxes in the production segment reflect the rise in revenue from higher prices for crude oil and a $0.1 billion increase in tax offsets from special charges. The decreased taxes in the refining/marketing segment reflect the fall in refining margins resulting from the rise in crude oil prices and a decrease in refinery output. Tax offsets had little effect on the change in tax liabilities in the refining/marketing segment since the offsets were at approximately the same level as a year earlier.

The increase in foreign income taxes and the decrease in total U.S. income taxes raised the 1989 share of foreign income tax expense in worldwide pretax income to 24 percent, substantially above the 21 percent share of a year earlier but still the second lowest since the FRS system was established (Table 13 and Figure 10). The increase in foreign taxes was associated with changes in the allocation of those taxes among foreign countries.

The FRS system allocates foreign income taxes to six geographical areas. These geographically-allocated taxes are available only for current taxes, which in 1989 accounted for 97 percent of all foreign taxes. The relative importance of the various areas in allocated current taxes typically changes slowly over time. The distribution of current taxes to a large extent reflects the diversification of foreign sources of crude oil supply, the allocation of which also usually changes slowly over time.

Figure 10. Income Taxes as a Percent of Worldwide Pretax Income for FRS Companies, 1981-1989



Source: Energy Information Administration, Form EIA-28.

The most important geographic change in current income tax liabilities and crude oil production in 1989 was for the European member countries of the Organization for Economic Cooperation and Development (OECD). European OECD production of crude oil and natural gas liquids fell by 12 percent and current tax liabilities fell by $0.5 billion (Table 16). The declines reflect continued North Sea supply interruptions resulting from accidents and maintenance and safety operations. As a result, the North Sea area accounted for less than one-third of the FRS companies' foreign crude oil and natural gas liquids production and about 30 percent of foreign current income taxes, the smallest shares since at least 1982. Substantial increases in current taxes occurred in both Africa ($0.4 billion) and the Middle East ($0.3 billion) even though production was relatively stable. Canada fell to third place as a source of foreign crude oil and natural gas liquids production even though production increased by more than 1 percent and current taxes increased by $0.2 billion.

The need to expand crude oil production capacity is likely to contribute further to the relative shift in the allocation of funds by FRS companies from domestic petroleum development to petroleum development abroad. The major reason for the shift during recent years has been the existence of lower developmental costs abroad while, at the same time, the potential for discovering substantial domestic fields has dwindled. Relaxed foreign petroleum fiscal regimes and the U.S. ban on drilling in prospective offshore and Alaskan areas have also contributed to the relative shift in the allocation of funds.

FRS and Industry Effective Tax Rates

Effective income tax rates did not change greatly for the FRS companies during 1989 relative to the volatile movements of the prior few years.[23] The aggregate rate for the FRS companies rose and continued to exceed the rate for the S&P 400 group of companies but only by a small margin. The disparity between domestic and foreign rates for the FRS companies is estimated to have narrowed slightly as the average U.S. rate fell slightly and the average foreign rate rose by a small amount. Generally, effective rates for virtually all domestic and foreign lines of business and business segments were also highly stable. The stability in rates largely reflects the continuing effects of the Tax Reform Act of 1986.

In 1989, the worldwide effective income tax rates for the FRS companies and the S&P 400 group, based on combined current and deferred taxes, each rose by about 1 percentage point but remained close to their historic lows reached a year earlier. The FRS companies' rate rose to 40.3 percent from 39.4 percent whereas the S&P 400 group's rate rose to 37.5 percent from 36.1 percent (Figure 11, Part A). Although the FRS companies' rate continued to exceed the S&P 400 group's rate, the differential narrowed to the smallest margin since the FRS system was established: 2.8 percentage points. The principal source of the rise in the FRS companies' rate was in foreign petroleum.

The effective rates for the FRS companies (as well as for the S&P 400 group of companies) have historically been substantially lower when only current income taxes are considered and deferred income taxes are excluded (Figure 11, Part B). Recently, this relationship changed dramatically. The present close approximation in effective rates with and without deferred taxes reflects the sharp reduction in deferred taxes due to the Tax Reform Act of 1986, special environmental charges, and other factors (Figure 11, Parts A and B).

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[23] There are two major categories of effective tax rates: average and marginal. Average effective rates are typically based on actual historical performance and measure tax burdens from prior investments under former and current tax laws. Marginal effective rates, on the other hand, are typically based on expected tax payments from potential incremental investments under current and expected future tax laws. The effective rates in this report are average rates and are calculated by dividing income tax expense by pretax income.

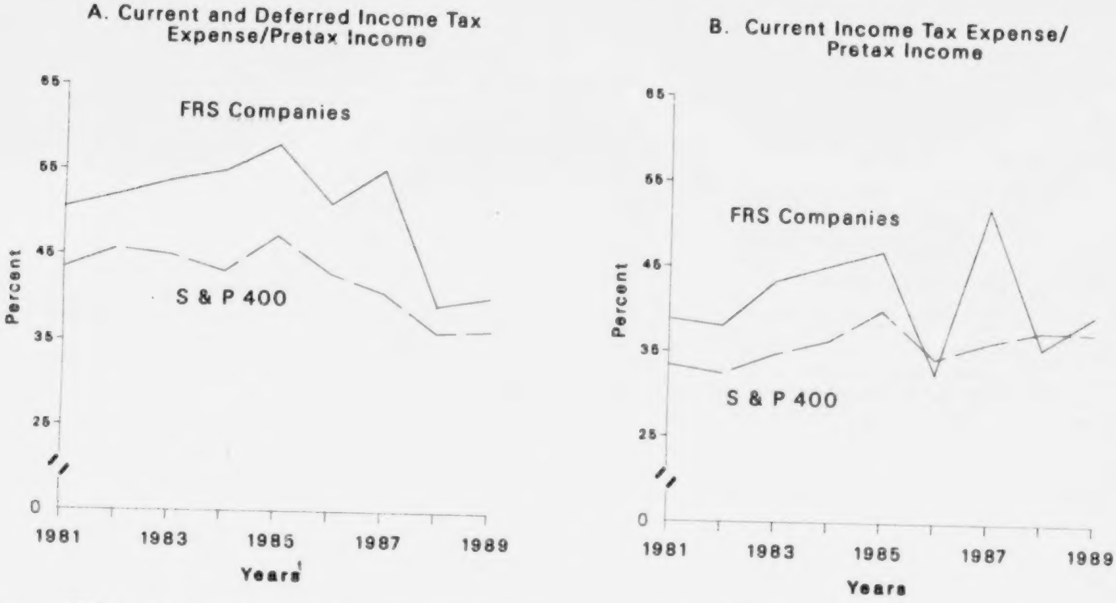
Table 16. Composition of Income Tax Expense for FRS Companies, 1985-1989
(Billion Dollars)

Income Tax Sources	1985	1986	1987	1988	1989	Percent Change 1988-1989
Pretax Income[a]	43.6	20.6	25.0	34.3	32.3	-5.8
U.S. Federal Income Taxes						
Current	3.1	-1.3	3.7	3.8	4.0	4.9
Deferred	3.4	2.6	0.7	1.7	0.1	-95.9
Total U.S. Federal	6.5	1.3	4.4	5.5	4.1	-25.6
State and Local Income Taxes						
Current	0.8	0.4	0.7	0.9	1.1	18.5
Deferred	0.0	0.1	0.0	-0.1	0.0	NM
Total State and Local	0.8	0.5	0.7	0.8	1.0	22.6
Foreign Income Taxes						
Current						
Canada	1.6	0.7	0.9	0.5	0.7	39.7
OECD Europe	5.9	3.0	3.1	2.8	2.3	-20.4
Africa	4.3	1.4	1.5	1.2	1.6	37.8
Middle East	1.7	0.7	1.1	0.7	1.0	48.8
Other Eastern Hemisphere	1.9	1.2	1.3	1.4	1.5	4.4
Other Western Hemisphere	1.0	0.6	0.7	0.7	0.6	-11.4
Total Current	16.5	7.6	8.5	7.3	7.7	5.1
Deferred	1.5	1.0	0.1	-0.2	0.2	NM
Total Foreign	18.0	8.6	8.7	7.1	7.9	10.1
Total Income Tax Expense	25.3	10.5	13.8	13.5	13.0	-3.6

[a] Includes minority interest in income; excludes extraordinary items and cumulative effect of accounting changes.
NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Effective foreign income tax rates for the total foreign operations of the FRS companies have historically exceeded effective U.S. rates on domestic operations. Beginning with 1987, data on pretax income for total foreign versus total domestic operations were no longer reported to the FRS system. However, a geographic comparison limited to the petroleum line of business continues to be possible (Table 17). The effective rate for foreign petroleum rose from 49 percent in 1988 to 51.7 percent in 1989, while the U.S. rate fell from 35.4 percent to 34.0 percent. About one-third of the rise in the foreign rate resulted from changes in effective rates for individual petroleum segments (Table 18). The other two-thirds resulted form an increase in the relative importance of the high-tax-rate petroleum production segment. In the United States, all of the fall in the effective rate for the petroleum line of business resulted from changes in effective rates for individual segments. Although the 1989 rate for high-tax-rate U.S. petroleum production rose and the importance of that segment also increased relative to the other petroleum segments, the effective rate for the entire U.S. petroleum line of business fell because of the rate decreases in these other segments.

Figure 11. Worldwide Effective Income Tax Rate for FRS Companies and S&P 400, 1981-1989



A. Current and Deferred Income Tax Expense/Pretax Income

B. Current Income Tax Expense/Pretax Income

Sources: o FRS Companies: Energy Information Administration, Form EIA-28
o S&P 400: Standard & Poor's Compustat Services, Inc.

Deferred Income Taxes

Deferred income taxes are important in evaluating the financial condition of FRS companies as well as companies in other industries.[24] This importance has resulted from two basic economic benefits that companies have historically derived from them. First, since by definition deferred income tax expenses are not paid in the reporting period in which they accrue, they do not involve a current period cash outflow. Therefore, they provide a portion of the cash flow available to companies for investment and other purposes. Second, they provide implicit and explicit opportunities to generate earnings on the deferred cash outflow. For the FRS companies, deferred taxes historically have arisen mainly from the way that certain costs are treated for tax purposes. These costs include capital recovery (through charges for depreciation, depletion, and amortization) and the expensing of certain exploration and development costs. They also include a wide variety of other sources.

In 1989, total deferred income tax expense for the FRS companies fell sharply to a historic low not only in absolute terms but also relative to total (current and deferred) income tax expense. The decrease was from $1.3 billion in 1988 to $0.2 billion in 1989 (Table 19). Relative to total income tax expense, the decrease was from 9 percent to less than 2 percent. The decrease resulted mainly from special developments that affected a small number of companies rather than from changes in capital recovery costs and in the expensing of certain exploration and development costs (Table 20).

[24] Deferred taxes are differences between income tax expense accrued under Generally Accepted Accounting Principles for financial reporting purposes and income taxes currently payable in the reporting period. They originate from a variety of sources and are important to the financial operations of energy companies, as well as to industry in general. Basically, deferred taxes originate because of timing differences in reporting revenue and expense for financial reporting and tax reporting. Financial reporting attempts to match items of income and expense in the periods in which they occur. Tax reporting may permit different timing for recognizing revenues and deducting expenses. For example, faster writeoffs of depreciable properties are permitted under tax laws while they may not be acceptable under financial accounting principles. Accelerated writeoffs result in lower taxable income and thus lower tax liability in the year taken. In future periods, however, taxable income and income taxes payable may be higher than pretax income for financial reporting purposes because the timing differences between tax and financial reporting are reversed.

Table 17. U.S., Foreign, and Worldwide Effective Income Tax Rates for FRS Companies, 1985-1989
(Percent)

Area	1985	1986	1987	1988	1989
U.S. Petroleum	44.4	48.3	40.5	35.4	34.0
Foreign Petroleum	68.9	49.3	55.9	49.0	51.7
Worldwide Petroleum	55.5	48.9	48.2	41.8	42.7
Worldwide Nonpetroleum	23.9	34.5	34.8	33.1	34.1
Worldwide Petroleum and Nonpetroleum	53.5	46.4	44.3	38.7	39.8
Worldwide Consolidated	58.0	51.1	55.1	39.4	40.3

Note: The effective rates, except for worldwide consolidated rates, are calculated on income tax expenses and pretax incomes allocated to individual lines of business. They do not include the taxes and pretax incomes that could not be allocated to those lines. Worldwide consolidated data are based on all income taxes and pretax incomes. All income tax expenses include both current and deferred taxes.

Source: Energy Information Administration, Form EIA-28.

Table 18. U.S. and Foreign Effective Income Tax Rates for Petroleum for FRS Companies, 1987-1989
(Percent)

Area	1987	1988	1989
Domestic			
Production	39.0	39.0	42.1
Refining/Marketing	21.2	34.5	27.7
Pipelines	40.3	33.9	33.1
Consolidated	40.5	35.4	34.0
Foreign			
Production	58.0	54.1	56.1
Refining/Marketing	34.8	38.0	37.1
International Marine	-15.5	10.7	8.4
Consolidated	55.9	49.0	51.7

Note: The effective rates are calculated on income tax expenses and pretax incomes allocated to individual lines of business. They do not include the taxes and pretax incomes that could not be allocated to those lines. All income tax expenses include both current and deferred taxes.

Source: Energy Information Administration, Form EIA-28.

Special developments affecting three FRS companies more than fully account for the decrease in deferred taxes. The departure of Tenneco from the FRS system in 1989 accounts for about two-thirds of the decrease, under the assumption that its deferred taxes would have remained the same in that year as in the prior year. Environmental provisions contributed to a sharp decline in deferred taxes for Exxon. Special environmental charges and matters related to the Pennzoil settlement caused Texaco's deferred tax expense to decline sharply. In the absence of special developments for these and other companies, FRS companies' total deferred taxes would likely have changed by a much smaller amount from 1988 to 1989.

Table 19. Deferred, Current, and Total Income Tax Expense for FRS Companies, 1985-1989

Tax Component	1985	1986	1987	1988	1989
	(million dollars)				
Deferred	4,877	3,806	768	1,279	217
Current	20,409	6,712	13,009	12,217	12,796
Total	25,286	10,518	13,777	13,496	13,013
	(percent distribution)				
Deferred	19.3	36.2	5.6	9.5	1.7
Current	80.7	63.8	94.4	90.5	98.3
Total	100.0	100.0	100.0	100.0	100.0

Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table 20. Sources of Deferred Income Tax Expense for FRS Companies, 1985-1989

Source	1985	1986	1987	1988	1989
	(million dollars)				
Depreciation, Depletion and Amortization (DD&A)	5,179	3,419	1,846	196	9
Provisions Related to Exploration and Development (E&D)[a]	1,241	-126	-258	-669	25
Other Sources[b] [c]	-1,543	514	-820	1,752	183
Total	4,877	3,806	768	1,279	217
United States	3,388	2,761	654	1,438	25
Foreign	1.489	1,046	114	-159	192
	(percent distribution)				
Depreciation, Depletion and Amortization (DD&A)	106.2	89.8	240.4	15.3	4.1
Provisions Related to Exploration and Development (E&D)	25.4	-3.3	-33.6	-52.3	11.5
Other Sources	-31.6	13.5	-106.8	137.0	84.3
Total	100.0	100.0	100.0	100.0	100.0
United States	69.5	72.5	85.2	112.4	11.5
Foreign	30.5	27.5	14.8	-12.4	88.5

[a] Principally intangible drilling costs.

[b] Includes unknown amounts that apply to the other individually listed categories.

[c] The values for this category were adjusted so that the sum for all categories add to the totals shown. Data for the individual categories are estimated from company annual reports. Totals are from the FRS system.

Note: Sum of components may not equal total due to independent rounding.

Sources: Company annual reports for the reporting year shown except for totals (including United States and Foreign) and Other Sources. Totals are from Form EIA-28.

Other Sources are calculated as the difference between the total and the sum of the first two deferred tax components shown.

Deferred taxes generated from depreciation, depletion, and amortization (DD&A) also contributed to the overall decline in deferred taxes in 1989, while those generated from exploration and development expenditures (E&D) tended to increase the overall level. Generally, deferred taxes generated from DD&A reflect the use of shorter asset lives and higher initial rates of depreciation for tax purposes (the combination is termed "accelerated depreciation") than for financial reporting purposes. The most important determinant of DD&A is the amount of new investment, as reflected by additions to property, plant and equipment (PP&E). Deferred taxes generated from E&D expenditures reflect tax laws that allow energy producers, principally oil and gas producers, to expense on a current basis certain E&D costs which for financial accounting purposes must be capitalized and written off over time. These expenditures consist principally of intangible drilling and development costs (IDCs).

The 1989 fall in deferred taxes related to DD&A amounted to $0.2 billion and reflected a large decrease in PP&E expenditures in the same year. Deferred taxes related to E&D expenditures, on the other hand, rose from a large negative amount ($0.6 billion) in 1988 to approximately zero in 1989 (Table 20), despite a decrease in E&D expenditures. The reason for this development is that tax levels are affected not only by current year E&D expenditures but also by those in prior years, and a large expenditure increase had occurred from 1987 to 1988.

The operation of the corporate Alternative Minimum Tax (AMT) system also affected the level of deferred taxes in 1989. The AMT system became effective for tax years after December 31, 1986. In effect, it operates as a separate domestic income tax system parallel to the regular system and substantially broadens the U.S. tax base. Corporations must pay 20 percent of the broadened base in taxes if such taxes exceed those generated by the regular system. For the FRS companies, AMT current income taxes exceeded basic current income tax expense by $24 million in 1989 in contrast to $174 million a year earlier. Since the excess is carried forward indefinitely as a credit against any future year regular income tax that exceeds the minimum tax, the excess for each year was reflected as a negative deferred tax expense and contributed to the overall decline in deferred taxes. However, since the negative deferred tax expense in 1989 was less that for 1988, the effect was to constrain the overall fall in deferred taxes between those years.

The values involved in the operation of the AMT system are small for the FRS companies in the aggregate, but large for many individual companies. Ten FRS companies were particularly affected by the AMT system in 1989. For about half of these companies, current income taxes were 87 percent greater than they would have been in the absence of the system. For the other half, current income taxes were 23 percent lower.

Changes in the method of accounting for income taxes required by the Financial Accounting Standards Board to be implemented no later than company fiscal years beginning after December 15, 1991 were adopted by three FRS companies during 1989, raising the total number of FRS companies that adopted the change to eleven.[25] One of the most important changes essentially requires that the tax liabilities on company balance sheets be adjusted to reflect enacted rates rather than rates in effect at the time the liabilities were incurred. The interaction of this change with the Tax Reform Act of 1986's reduced rate of 34 percent probably contributed further to the aggregate reduction of deferred income tax expense.

Non-Income Taxes

The FRS companies pay many taxes in addition to income taxes. Comprehensive data for these non-income taxes are available only for those paid to U.S. government authorities. The importance of these taxes is substantial and they have remained relatively stable since 1987 both in dollar terms and relative to income tax expense. The principal reason for the stability has been the elimination of the Windfall Profits Tax (WPT), which had produced large annual changes in non-income taxes prior to 1986. Although the WPT was not repealed until August 1988, virtually no liabilities were incurred from that source from 1986 through 1988 because of low prices for crude oil.[26] Further contributing to the stability has been the reduced number of legislated changes to State severance tax rates.

In 1989, the non-income tax liabilities of the FRS companies rose to $8.2 billion, or by $0.2 billion from a year earlier (Table 21). The principal source of the increase was in severance taxes, where increased liabilities associated with higher crude oil prices more than offset decreased liabilities associated with decreased domestic production of crude oil and natural gas. Severance taxes continued to be one of the major sources of non-income tax liabilities, accounting for more than one-fourth of such liabilities in 1989. The most important other sources were sales, use and property taxes (about one-third) and payroll taxes (about one-fourth), each of which decreased in dollar terms from 1988 to 1989.

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[25] The changes in accounting treatment for income taxes are the most comprehensive in decades. See Financial Accounting Standards Board, *Statement of Financial Accounting Standards, No. 96: Accounting for Income Taxes* (Stamford, Connecticut, December 1987).

[26] The WPT was a Federal percentage excise tax that was applied to the excess of the per-barrel first sale price of crude oil produced in the United States over an inflation-adjusted base price for the oil. The excess was essentially eliminated in 1986 as selling prices collapsed and it did not re-emerge by the time the WPT was repealed in 1988.

Despite the increase in non-income tax liabilities in 1989, they continued to account for 37 percent to 39 percent of worldwide total FRS tax liabilities, as they have since 1987, and to exceed U.S. income tax liabilities by 60 percent.

Table 21. Additional U.S. Tax Liabilities of FRS Companies, 1985-1989
(Billion Dollars)

Tax Category	Total					Petroleum				
	1985	1986	1987	1988	1989	1985	1986	1987	1988	1989
Windfall Profits Tax	3.5	-0.1	-0.3	-0.2	0	3.5	-0.1	-0.3	-0.2	0
Severance Tax	3.5	1.8	2.1	1.9	2.3	3.3	1.7	2.0	1.8	2.1
Superfund	NA	NA	0.3	0.2	0.2	NA	NA	0.2	0.2	0.2
Import Duties	0.1	0.1	0.2	0.2	0.2	0.1	0.1	NA	NA	NA
Sales and Use; Property	3.0	3.4	2.9	2.8	2.6	2.2	2.5	NA	NA	NA
Payroll	2.3	2.2	2.0	2.1	1.9	0.7	0.8	NA	NA	NA
Other	1.0	1.0	1.0	1.0	1.0	0.7	0.7	NA	NA	NA
Total[a]	13.4	8.4	8.2	8.0	8.2	10.5	5.7	NA	NA	NA

[a] Excludes excise taxes collected on behalf of governments.
NA = Not available.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

4. Domestic Petroleum Developments

Overview

Several dramatic events affected the U.S. petroleum industry in 1989. The effects of the *Exxon Valdez* accident, record breaking cold in December, and refinery outages due to Hurricane Hugo and the San Francisco earthquake, put considerable stress on the U.S. petroleum industry and the consuming public. Perhaps the most permanent effect of these events has been increased environmental awareness following the *Exxon Valdez* disaster, coupled with increased expenditures to protect the environment. Although these dramatic events materially influenced the financial performance of the FRS companies in 1989, fundamental developments in energy markets and costs provided the basis for understanding financial developments.

In 1989, U.S. crude oil production fell to the lowest level in 25 years and petroleum imports increased to the highest level since 1979.[27] While motor gasoline consumption fell slightly in 1989, only in 1978 was consumption higher than in 1988 and 1989. Net imports of crude oil and petroleum products accounted for 41 percent of refined product supplied in 1989. Net imports from the Organization of Petroleum Exporting Countries (OPEC) increased by 17 percent over 1988. As a result, OPEC's share of U.S. net petroleum imports increased from 53 percent in 1988 to 58 percent in 1989.

Income

The average U.S. wellhead crude oil price increased from $12.58 in 1988 to $15.85 in 1989.[28] At the same time, U.S. crude and NGL production fell to an average of 9.2 million barrels per day, the lowest level since 1965.[29] Natural gas production increased by 1 percent to 17.3 trillion cubic feet while the average wellhead natural gas price remained at $1.69 per thousand cubic feet.[30] Increasing natural gas demand, which reached the highest level since 1981, stimulated production gains. These developments are indicative of the growing role of natural gas in U.S. energy use.

Overall, the FRS companies' net income from U.S. oil and gas production fell 4 percent to $3.1 billion (Table 22). Except for the oil price crash of 1986, this was the lowest level recorded since these data were first collected in 1977. However, financial results were affected by large accounting adjustments in both 1988 and 1989. In 1988, net income was increased by $1.3 billion primarily due to Tenneco's sale of its oil and gas assets. In contrast, unusual items reduced 1989 net income by $1.0 billion. These unusual items related mainly to writedowns of oil and gas assets. For example, Chevron and Phillips reported total after-tax adjustments to income of $725 million for writedowns of offshore California properties.[31] Excluding the effects of unusual items, the FRS companies' net income from U.S. oil and gas operations more than doubled between 1988 and 1989.

The rate of return on FRS oil and gas assets rose slightly in 1989, but remained at a low level (Figure 12). Similarly, independent oil and gas producers experienced a modest recovery in profitability in 1989 but their rate of return was barely positive (Figure 13).

The refining/marketing segment saw rapid gasoline price increases following the *Exxon Valdez* oil spill in March. In late December, heating oil prices shot up due to record cold weather and numerous refinery outages. December 1989 will be remembered for the record cold that swept across the eastern half of the United States. The record cold caused a large increase in the demand for fuel oil. The cold weather also forced several refineries to curtail operations. An explosion at Exxon's Baton Rouge refinery, one of the largest in the United States, tightened the supply situation even further. Subsequently, the Energy Information Administration provided a report to Congress with a detailed analysis of the situation. The report's most pertinent conclusions concerning profitability were the following:

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[27] The discussion in this paragraph is based on Energy Information Administration, *Petroleum Supply Monthly*, December 1989, DOE/EIA-0109(89/12) (Washington, DC, February 1990), pp. xiii-xxi.

[28] Energy Information Administration, *Monthly Energy Review June 1990*, DOE/EIA-0035(90/06), Table 9.1.

[29] Energy Information Administration, *Annual Energy Review 1989*, DOE/EIA-0384(89) (Washington, DC, May 1990), Table 50.

[30] Energy Information Administration, *Monthly Energy Review June 1990*, DOE/EIA-0035(90/06), Tables 4.1 and 9.11.

[31] Note that Exxon's $1.7 billion after-tax charge related to the *Exxon Valdez* disaster was recorded against corporate income rather than against U.S. oil and gas income.

"On balance, the U.S. refining sector fared poorly in terms of financial results during the 1989-90 heating season, compared with the same period in 1988-89. Income from major petroleum companies' U.S. refining/marketing operations fell 70 percent in the fourth quarter of 1989 and 48 percent in the first quarter of 1990, compared with the same quarters of the previous year. Independent U.S. refiners registered comparable declines in net income of 57 percent and 32 percent, respectively. As a result, the profitability of the majors and other refiners, as measured by return on equity, remained below that of the rest of U.S. industry. While there may have been isolated cases in which margins and profits were unusually high and consumers paid very high prices, the market as a whole functioned well under extremely difficult circumstances. In the context of the entire 1989-90 heating season, the industry and the consumer shared the extra cost."[32]

For 1989 as a whole, crude oil input price increases outstripped overall product price increases. The FRS companies' U.S. refining/marketing income fell, by 17 percent, from the record high level enjoyed in 1988. It is ironic, given the public perception of oil company "profiteering" during these stressful events that profitability was actually lower in 1989 than during 1988 (Figure 12).

Table 22. U.S. Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1986-1989
(Billion Dollars)

Petroleum Segment	1986	1987	1988	1989	Percent Change 1988-1989
U.S. Petroleum					
Top Four	1.7	2.2	3.2	1.7	-45.6
Five Through Twelve	2.9	4.7	4.7	5.5	18.4
All Other	0.6	1.5	2.7	2.2	-17.7
All FRS	5.2	8.4	10.6	9.5	-10.2
Excluding Unusual Items	6.5	8.7	9.8	11.0	11.9
U.S. Petroleum Segments					
Production					
Top Four	1.0	1.8	0.4	0.9	130.9
Five Through Twelve	-0.1	2.2	1.1	1.3	15.9
All Other	-0.03	0.7	1.6	0.8	-51.1
All FRS	0.9	4.7	3.2	3.1	-3.6
Excluding Unusual Items	1.8	4.8	1.9	4.1	116.0
Refining/Marketing					
Top Four	-0.2	-0.1	2.2	0.3	-88.3
Five Through Twelve	2.0	1.2	2.5	3.3	35.4
All Other	-0.2	0.05	0.8	0.9	15.9
All FRS	1.6	1.1	5.4	4.5	-16.9
Excluding Unusual Items	2.0	1.1	5.3	5.0	-5.9
Pipelines					
Top Four	0.7	0.6	0.6	0.5	-14.8
Five Through Twelve	1.1	1.3	1.1	0.9	-18.1
All Other	0.8	0.7	0.3	0.5	71.2
All FRS	2.6	2.6	2.0	1.9	-3.9
Excluding Unusual Items	2.6	2.8	2.5	1.9	-22.7

NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

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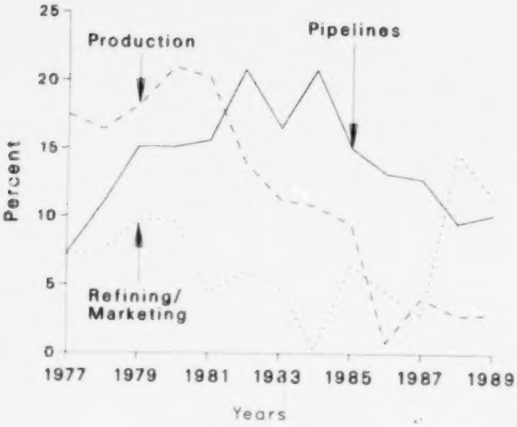
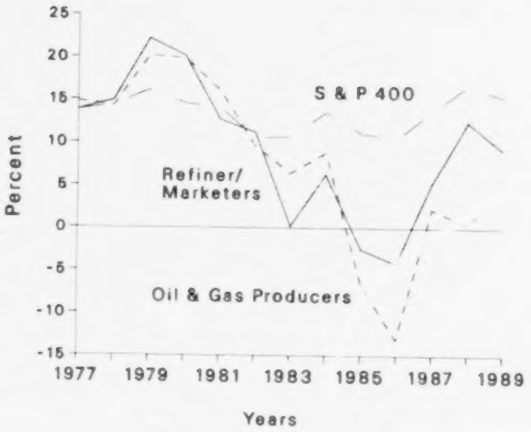
[32] Energy Information Administration, *An Analysis of Heating Fuel Market Behavior, 1989-1990*, SR/OG/90-01 (Washington, DC, June 1990), p. xi.

Figure 12. Profit Rates in U.S. Petroleum Segments for FRS Companies 1977-1989



Note: Profit rate is net income divided by net investment in place.
Source: Energy Information Administration, Form EIA-28.

Figure 13. Net Income as a Percent of Stockholders' Equity for Publicly Traded Non-FRS Oil and Gas Producers, Refiner/Marketers, and S&P 400, 1977-1989



Source: Standard & Poor's Compustat Services, Inc., annual data items 172 and 216.

Investment

The FRS companies' capital investments in the U.S. petroleum industry fell across all business segments. Overall, U.S. petroleum capital expenditures fell by 28 percent to $18.2 billion (Table 23). The sharpest cut was for U.S. production, where spending fell by a third to $11.9 billion. This was only the second year since 1978 that investment in U.S. production operations was less than $12 billion.

However, several one-time events that contributed to unusually large expenditures in 1988 accentuated the fall in capital spending for production activities. For example, about half the $5 billion spent for proved acreage in 1988 related to the purchase of Tenneco's oil and gas assets.[33] A large increase in Federal Outer Continental Shelf (OCS) acreage offered for lease led to a large increase in offshore unproved acreage expenditures. Further, scheduled expiration of over a thousand OCS leases in 1988, prompted an increase in offshore exploratory drilling to maintain these leases. In 1989, acquisition of proved and unproved acreage each fell by more than 50 percent and offshore exploratory well completions fell by 28 percent (see Chapter 5).

The FRS companies' refining/marketing investment fell 18 percent to $5.5 billion. The decline was due to a fall in refining investment from $3.7 billion in 1988 to $2.4 billion in 1989 (Table 6). However, marketing investment remained at last year's record high of $2.8 billion. Capital expenditures related to FRS companies' mergers and acquisitions in U.S. refining/marketing fell from $1.2 billion in 1988 to $0.3 billion in 1989.

Mergers and acquisitions were a more important factor in capital expenditures during 1988 than in 1989. In 1988, BP America bought Mobil's Washington refinery with capacity of 77 thousand barrels per day; Mobil bought Tenneco's Louisiana refinery with capacity of 145 thousand barrels per day; and Sun Corporation acquired Atlantic Refining whose Pennsylvania refinery had a capacity of 125 thousand barrels per day. In 1989, only one transaction occurred. This was the acquisition by USX of Rock Island Refining, whose Indiana refinery had a capacity of 50 thousand barrels per day. Adjusting for the effects of mergers and acquisitions, production expenditures fell by 17 percent and refining/marketing expenditures fell by 6 percent (Table 6).

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[33] Energy Information Administration, *Performance Profiles of Major Energy Producers 1988*, DOE/EIA-0206(88) (Washington, DC, January 1990), p. 49.

Table 23. Additions to Investment in Place in U.S. Petroleum for FRS Companies Ranked by Total Energy Assets, 1986-1989
(Billion Dollars)

Petroleum Segment[a]	1986	1987	1988	1989	Percent Change 1988-1989
U.S. Petroleum					
Top Four	5.3	5.3	9.6	6.2	-35.0
Five Through Twelve	14.7	8.6	10.6	7.5	-29.2
All Other	2.5	2.8	5.0	4.4	-12.8
All FRS	22.5	16.7	25.3	18.2	-28.2
U.S. Petroleum Segments					
Production					
Top Four	3.5	3.6	6.2	4.3	-30.5
Five Through Twelve	7.6	6.1	8.2	4.9	-41.0
All Other	1.6	1.7	3.4	2.7	-18.2
All FRS	12.7	11.3	17.8	11.9	-33.0
Refining/Marketing					
Top Four	1.6	1.7	3.3	1.8	-44.1
Five Through Twelve	2.2	2.0	2.2	2.4	11.9
All Other	0.6	0.8	1.3	1.3	-3.3
All FRS	4.5	4.5	6.8	5.5	-18.1
Pipelines					
Top Four	0.1	0.1	0.2	0.1	-27.5
Five Through Twelve	4.9	0.6	0.2	0.3	5.2
All Other	0.3	0.3	0.3	0.3	2.4
All FRS	5.3	0.9	0.7	0.7	-2.8

[a] Measured as additions to property, plant, and equipment plus additions to investments and advances.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Oil and Gas Production

The FRS companies' production of crude oil and NGLs fell by 9 percent during 1989 (Table 24). Falling production occurred despite a 21-percent increase in the average FRS wellhead price, from $11.78 to $14.19 per barrel. The first full year of decline in Alaskan production was an important contributor to the fall in production. Natural gas production from continuing operations rose by 5 percent for FRS companies.[34] However, aggregate output accounted for by the FRS group fell 2 percent because producing assets were sold. Overall, natural gas has a growing role in the U.S. energy industry and the FRS companies can be expected to increase the role of natural gas in their production activities. This is likely to be the case even though the ownership changes noted earlier reduced the FRS share of U.S. natural gas production from 46 percent in 1988 to 44 percent in 1989 (Figure 2).

Increased prices offset the financial effects of the decline in crude oil and NGL production, resulting in a 12-percent increase in crude oil revenue to $30.9 billion in 1989 (Table 25). However, due to lower wellhead prices and lower aggregate FRS output, natural gas revenue fell 2 percent to $15.0 billion. The FRS companies' depreciation, depletion, and amortization (DD&A) expenses fell 7 percent to $13.6 billion. Lower DD&A expenses reflected a fall in the U.S. oil and gas asset base for the second consecutive year.

Most cost components fell, particularly those related to exploratory activity. However, the out-of-pocket cost to produce oil and gas (lifting cost) increased by 2 percent to $16.4 billion (Table 25) despite the 6-percent fall in crude-oil-equivalent production (Table 24). Lifting cost apparently increased because higher crude oil prices induced additional production from relatively high-cost wells. Further, production taxes, which are typically on an *ad valorem* basis, rose in proportion to increased wellhead revenue. Exploratory expenses fell due to the sharp fall in the FRS companies' exploratory activity (Chapter 5). Dry hole expenses fell 27 percent to $1 billion while geological and geophysical (G&G) expenses fell 22 percent to $700 million.

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[34] This was computed after excluding Tenneco and Sun, both of which disposed of their producing assets in 1988.

Table 24. Average Prices, Sales, and Production in U.S. Oil and Gas for FRS Companies, 1986-1989

Prices, Sales, and Production	1986	1987	1988	1989	Percent Change 1988-1989
Oil and Gas Production and Sales[a]					
Production Volumes					
Crude Oil and NGL (million barrels)	2,089.6	2,069.5	2,102.1	1,911.1	-9.1
Dry Natural Gas (billion cubic feet)	7,143.6	7,214.1	7,627.3	7,480.7	-1.9
Total (million barrels, COE[b])	3,361.1	3,353.6	3,459.8	3,242.7	-6.3
Sales Volumes					
Crude Oil and NGL (million barrels)	2,277.7	2,293.8	2,347.0	2,179.9	-7.1
Dry Natural Gas (billion cubic feet)	7,697.4	7,810.9	8,717.7	8,621.9	-1.1
Total (million barrels, COE[b])	3,647.9	3,684.2	3,898.7	3,714.6	-4.7
Production Segment Per Unit Sale Values					
Crude Oil and NGL (dollars per barrel)	12.45	14.14	11.78	14.19	20.5
Crude Oil and NGL, Net of Windfall Profit Tax (dollars per barrel)	12.48	14.26	11.85	14.20	19.8
Dry Natural Gas (dollars per 1,000 cubic feet)	1.93	1.64	1.75	1.74	-0.7

[a] Production is on a net ownership basis. Sales are domestic production segment sales. See Appendix A for discussion of FRS reporting conventions.

[b] COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per 1,000 cubic feet.

Source: Energy Information Administration, Form EIA-28.

Overall, the $2.8 billion increase in operating revenue and $1.0 billion increase in operating expenses resulted in a $1.9 billion (56-percent) increase in operating income to $5.2 billion. To place this in perspective, this is one-fourth the level of $20.6 billion reported in 1985[35] and $3.1 billion less than the $8.3 billion reported in 1987 (Table 25). However, unusual items[36] reduced operating income by $1.5 billion in 1989. In contrast, unusual items increased operating income by $152 million in 1988. After netting out these unusual charges, operating income doubled from 1988 to 1989.

Refining and Marketing

For most years since the decontrol of oil prices in early 1981, excess capacity kept U.S. refining/marketing profitability below that of U.S. industry (Figure 13). Throughout most of the 1980's, U.S. refiner/marketers also faced changes in product demand and in the composition of crude oil supplies. Responses included reducing refinery distillation capacity and upgrading remaining capacity. Between 1981 and 1986, U.S. crude oil distillation capacity fell by more than 3 million barrels per day and over 100 refineries were closed.[37] Over the same period, U.S. refiners' capacity to produce higher octane, unleaded gasoline rose from 61 percent of crude oil distillation capacity to 70 percent, and capacity directed toward processing heavier, higher sulfur crude oils rose from 24 percent to 34 percent.

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[35] Energy Information Administration, *Performance Profiles of Major Energy Producers 1988*, DOE/EIA-0206(88) (Washington, DC, January 1990), Table 27.

[36] Unusual items are composed of gains and charges recognized in a company's income statement which are of a non-recurring nature and generally unrelated to current operations. These items include litigation settlements, gains and losses from large divestitures of assets, provisions for the cost of restructuring, and provision of reserves for future liabilities.

[37] Energy Information Administration, *Petroleum Supply Annual 1986*, DOE/EIA-0340(86)/1 (Washington, DC, May 1987), p. 65.

The division of each dollar of refining/marketing revenue illustrates the magnitude of the cost components embodied in refining/marketing. In 1989, 53 cents of each dollar of revenue covered raw material costs; 11 cents covered refinery operating expenses; 21 cents were required to purchase refined products and other miscellaneous supply expenses; 7 cents were spent for marketing expenses; and finally, 6 cents for each dollar of revenue was left over to pay DD&A expenses and income taxes. From the 6 cents, about 1 cent paid the taxes while 2 cents paid for DD&A. The result was that about 3 cents per dollar of revenue ended up as profit.

Table 25. Components of Revenues and Costs in U.S. Oil and Gas Production for FRS Companies, 1986-1989

Revenues and Costs	1986	1987	1988	1989	Percent Change 1988-1989
	(billion dollars)				
Operating Revenues					
Crude Oil and NGL	28.4	32.4	27.6	30.9	11.9
Natural Gas	14.9	12.8	15.2	15.0	-1.8
Operating Revenue	43.3	45.2	42.9	45.9	7.0
Windfall Profit Tax (WPT) Expense (Refund)	-0.1	-0.3	-0.2	-0.02	NM
Revenues Net of WPT	43.3	45.5	43.1	45.9	6.7
Operating Expenses (Net of WPT)					
Depreciation, Depletion, and Amortization (DD&A)	15.7	14.8	14.6	13.6	-7.2
Lifting Costs	16.0	15.7	16.2	16.4	1.6
Dry Hole Costs	2.0	0.9	1.4	1.0	-26.9
Geological and Geophysical Expenses	0.9	0.8	1.0	0.7	-22.1
Other Exploration and Development Expenses	1.9	1.3	0.7	1.3	81.4
Raw Material Purchases	3.8	3.7	4.4	5.0	12.1
Other Expenses (Revenues), Net	1.7	-0.02	1.4	2.6	92.4
Total Operating Expenses (Net of WPT)	42.0	37.2	39.7	40.7	2.5
Operating Income	1.3	8.3	3.3	5.2	56.1
Operating Income Excluding Unusual Items	2.9	8.4	3.2	6.7	110.0
	(dollars per barrel, COE)[a] [b]				
Operating Revenue (Net of WPT)	11.88	12.35	11.04	12.36	12.0
Operating Expenses (Net of WPT)	11.52	10.10	10.19	10.96	7.6
Operating Income	0.35	2.25	0.86	1.40	63.8
Operating Income Excluding Unusual Items	0.80	2.28	0.82	1.80	119.5
Contribution to Pretax Cash Flow[c]	5.21	6.52	4.98	5.34	7.3

[a] Financial items are divided by domestic production sales volumes of oil and gas on a COE basis.

[b] COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per 1,000 cubic feet.

[c] Sum of operating income, DD&A, and dry hole costs divided by domestic production sales volumes of oil and gas on a COE basis.

NM = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Until 1986, refining/marketing was the least profitable domestic petroleum line of business for the FRS companies (Figure 12). Parity was achieved only after a wrenching adjustment to long-term changes in market conditions and product requirements. The profitability of the FRS companies' U.S. refining/marketing line of business in 1989, at 11.5 percent, was second only to 1988 over the period of FRS data collection which began with the 1977 reporting year.

However, the U.S. refining/marketing operations' contribution to the FRS companies' net income fell 17 percent to $4.5 billion (Table 22). Large unusual accounting charges caused most of the fall in net income. Overall, the FRS companies' net income fell only 6 percent after excluding unusual items. The top four group's contribution to net income fell by 88 percent to $300 million.[38] The top four group of companies incurred the bulk of the unusual charges. For example, Chevron's U.S. refining/marketing segment reported charges for environmental costs of $320 million.[39] (As noted earlier, Exxon's $1.7 billion after-tax charge related to the *Exxon Valdez* disaster was recorded against corporate income rather than any line of business). Both the five through twelve and all other group of FRS companies reported increased income from U.S. refining/marketing activities. The five through twelve group increased by 35 percent to $3.3 billion and the all other group increased by 16 percent to $900 million. In contrast, independent refiners' return on equity fell to 9 percent, but remained higher than during any other year since 1982 (Figure 13). The profitability of U.S. industry remained well above refining profitability.

The FRS companies' raw material input cost increased by $3.05 per barrel in 1989 (Table 26). The average refined product price increased by a somewhat greater amount, $3.24 per barrel. However, other factors reduced the realized refined product margin by 30 cents per barrel. For example, a surge in purchases by the FRS companies of distillate and other products apparently cut into profits. Refinery outages and the jump in heating oil demand during December 1989, stimulated distillate purchases by the FRS companies, which increased by 21 percent to an FRS record high of 236 million barrels.[40] It is likely that a large portion of these purchases had not been resold to customers at the end of the year. Since the purchase cost was recorded but revenue had yet to be realized, operating income was reduced.

Ownership Changes

Significant changes in ownership of the refining industry are important for several reasons. If mergers and acquisitions increase market concentration, there may be competitive consequences. Acquisitions of U.S. refining facilities by foreign producing countries may have additional implications concerning U.S. access to crude oil imports. Overall, concentration in U.S. refining, as measured by the share of capacity accounted for by the four and eight largest refiners, fell slightly in 1989. The four-firm concentration ratio fell from 30.6 percent in 1988 to 29.7 percent in 1989.[41] The eight-firm concentration ratio fell from 48.3 percent to 47.1 percent over the same period.

The most substantial changes in refinery ownership since the mergers of 1982 and 1984 were completed in 1989. However, the former mergers primarily were intra-FRS and resulted in little net change in the overall FRS share of refining capacity. The ownership changes of 1989 caused a sharp fall in the FRS companies' share of U.S. refining capacity. The disposition of Texaco's interest in three of its refineries to the joint venture with Saudi Arabia, consummated in 1988, was effective at the beginning of 1989. As a result, Star Enterprise obtained over 600 thousand barrels per day of distillation capacity and over 10,000 gasoline stations.[42]

Also contributing to the decline in refining capacity was Atlantic Richfield's initial public offering of shares of its Lyondell Petrochemical subsidiary. Atlantic Richfield retained 49.9 percent of ownership and accounted for Lyondell on an equity basis in 1989. The Lyondell refinery had distillation capacity of almost 300 thousand barrels per day.

Unocal completed its previously announced joint-venture agreement with a subsidiary of Petroleos de Venezuela, S.A. (PDVSA) in December 1989. This involved the formation of a joint venture called Uno-Ven to own and operate Unocal's Chicago refinery and associated marketing outlets. The agreement included the refinery with capacity of 153 thousand barrels per day, 131 company-owned service stations, and supply contracts with 3,300 other service stations.[43] PDVSA agreed to supply 135 thousand barrels per day of Venezuelan crude oil for the joint venture. In December 1989, Unocal also ceased refining operations

[38] For this report and for all years in it, the companies were ranked by the 1988 book value of net PP&E plus investments and advances in petroleum, coal, nuclear, and other energy lines of business combined. The four companies in the "top four" group are Chevron, Exxon, Mobil, and Texaco. The "five through twelve" group includes the companies ranked 5 through 12, and the "all other" group includes the companies ranked below 12.

[39] Chevron Corporation, *Annual Report 1989*, p. 37.

[40] Refined product purchases are presented in Appendix B, Table B42.

[41] Calculated from data presented in Energy Information Administration, *Petroleum Supply Annual 1989*, DOE/EIA-0340(89)/1 (Washington, DC, May 1990) and previous editions.

[42] Texaco, Inc., *Annual Report 1989*, p. 13.

[43] Unocal Corporation, *Annual Report 1989*, p. 20.

Table 26. Sales, Expenses, and Income in U.S. Refining/Marketing for FRS Companies, 1986-1989

Sales, Expenses, and Income	1986	1987	1988	1989	Percent Change 1988-1989
	(billion dollars)				
Refined Product Sales	103.0	114.7	110.9	121.9	10.0
Other Revenues	46.8	55.4	56.8	67.6	19.0
Total	149.8	170.1	167.7	189.5	13.0
Operating Income	3.3	1.0	7.8	5.7	-26.1
Contribution to Net Income	1.7	1.1	5.4	4.6	-15.9
	(million barrels)				
Refined Product Sales	4,900.9	5,048.7	5,151.5	4,922.5	-4.4
	(dollars per barrel)				
Average Sales Price					
Gasoline	23.11	25.11	24.63	28.22	14.6
Distillate	20.69	21.94	20.22	24.01	18.7
Other	17.40	19.13	17.01	19.12	12.4
All Refined Products	21.02	22.73	21.53	24.77	15.1
Raw Material Input Cost per Barrel of Refinery Output	13.32	15.46	12.55	15.60	24.4
Refined Product Margin[a]	0.67	0.15	1.78	1.48	-16.8
Contribution to Pretax Cash Flow[b]	1.19	0.73	2.04	1.75	-14.1

[a] See Table B48 in Appendix B for the components to calculate the refined product margin.

[b] Sum of domestic refining/marketing operating income and DD&A, divided by the volume of refined products sold.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

at its Beaumont Refinery in Nederland, Texas, which had 74 thousand barrels per day of capacity.

Foreign countries continued to increase their participation in U.S. refining/marketing in 1989. Effective in January 1989, Coastal sold a 50-percent interest in its Pacific Refining subsidiary to China National Chemicals Import and Export Corporation (Sinochem). The transaction included a 55 thousand barrel per day refinery in Hercules, California and associated marketing facilities.

Two changes added new refining/marketing facilities to the FRS total in 1989. The addition of Total Petroleum as an FRS company brought in four additional refineries. (Note that while Total Petroleum is a subsidiary of a French company, it has operated in the United States for many years.) USX bought the Rock Island Refining operation in Indiana. Overall, six refineries with more than 1 million barrels per day of distillation capacity left the FRS group in 1989 and five refineries with more than 200 thousand barrels per day of capacity were added. The net decrease of 800 thousand barrels per day is reflected in the fall in the FRS companies' share of total U.S. distillation capacity from 75 percent in 1988 to 71 percent in 1989 (Table 27).

Ownership changes had a noticeable effect on apparent rates of refinery utilization. The FRS companies' refinery utilization rate was 85.4 percent in 1989, a slight drop from 1988 (Table 27). After adjusting for ownership changes,[44] the average utilization rate for the FRS companies increased to 87.0 percent, the highest rate since 1979. U.S. industry also increased its refinery utilization rate, to 86.3 percent which was the highest since 1978.[45]

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[44] Utilization rate is based on the average of beginning and end of year capacity. This means that the three Star Enterprise refineries are included when the average is calculated. This overstates the actual average capacity and thereby understates the average utilization rate.

[45] Energy Information Administration, *Petroleum Supply Monthly*, December 1989, DOE/EIA-0109(89/12) (Washington, DC, February 1990), p. xix.

Table 27. Refining Statistics for FRS Companies Ranked by Total Energy Assets, and for U.S. Industry, 1986-1989

Refining Statistics[a]	FRS Companies								U.S. Industry
	All FRS	Share of U.S.	Top Four	Share of U.S.	Five Through Twelve	Share of U.S.	All Other	Share of U.S.	
1986									
Refinery Output	11,459	76.8	4,168	27.9	4,804	32.2	2,487	16.7	14,927
Number of Refineries	94	42.2	32	14.3	33	14.8	29	13.0	223
Refinery Capacity									
End of Year	12,526	77.2	4,830	29.8	4,802	29.6	2,894	17.8	16,234
Utilization Rate	84.8	NM	80.3	NM	92.5	NM	79.8	NM	80.9
1987									
Refinery Output	11,712	77.6	4,459	29.6	4,820	32.0	2,433	16.1	15,085
Number of Refineries	91	41.9	30	13.8	33	15.2	28	12.9	217
Refinery Capacity									
End of Year	12,462	75.2	4,789	28.9	4,841	29.2	2,832	17.1	16,581
Utilization Rate	84.3	NM	80.2	NM	91.1	NM	79.9	NM	81.1
1988									
Refinery Output	12,033	78.0	4,626	30.0	4,955	32.1	2,452	15.9	15,426
Number of Refineries	91	44.0	29	14.0	34	16.4	28	13.5	207
Refinery Capacity									
End of Year	12,281	75.4	4,651	28.6	4,937	30.3	2,693	16.5	16,285
Utilization Rate	86.1	NM	82.6	NM	91.1	NM	83.0	NM	82.7
1989									
Refinery Output	11,413	72.9	4,153	26.5	4,794	30.6	2,466	15.8	15,655
Number of Refineries	90	43.1	26	12.4	34	16.3	30	14.4	209
Refinery Capacity									
End of Year	11,489	70.8	4,024	24.8	4,816	29.7	2,649	16.3	16,238
Utilization Rate	85.4	NM	78.8	NM	89.5	NM	88.6	NM	85.2

[a] Refinery output and capacity data are in thousand barrels per day. Share is the percentage of the U.S. total. U.S. industry includes Puerto Rico and the Virgin Islands.

NM = Not meaningful.

Sources: FRS companies: Energy Information Administration, Form EIA-28. U.S. industry: Refining capacity data computed from data in the Energy Information Administration's *Petroleum Supply Annual* 1989, DOE/EIA-0340(89)/1 (Washington, DC, May 1990) and previous editions. Domestic industry refinery output data computed from the above source and supplemented by data for the Virgin Islands and Puerto Rico compiled for the International Energy Agency by the Office of Oil and Gas, Energy Information Administration.

Refinery Investments and Upgrading

The FRS companies invested $5.5 billion in U.S. refining/marketing operations during 1989 (Table 23). While this was 18 percent below the 1988 level, it was higher than for any other year since 1982 (Figure 14). The fall in expenditures was due to the decline in refining investment (measured by additions to net investment in place) from $3.7 billion in 1988 to $2.4 billion in 1989 (Table 6). Expenditures for marketing additions remained constant at the record level of $2.8 billion reported in 1988. Marketing expenditures were concentrated on projects to upgrade retail networks and to meet environmental requirements. In the period of FRS data collection, marketing investment has exceeded refining investment only twice, in 1987 and 1989.

A large proportion of the refining/marketing expenditures was environmentally related. It is not possible to separate capital expenditures, increased operating expenses, and accounting reserves by using the companies' public disclosures. However, most FRS companies did disclose environmental costs in one or more of these categories. In total, these costs amounted to $900 million or over 15 percent of refining/marketing operating income in 1989, and most companies expected such costs to increase in 1990.[46]

The changes in ownership of FRS refineries and the influx of refineries formerly outside the FRS group obscured the capacity increases resulting from investments for refinery upgrading. The refineries that left the FRS group in 1989 had 859 thousand barrels per day of octane/unleaded boosting capacity while the refineries that entered the group had only 183 thousand barrels per day. In terms of heavy/sour capacity, 457 thousand barrels per day left the FRS group and 29 thousand barrels per day entered. Overall, FRS octane/unleaded boosting capacity fell by 7 percent (Table 28) while U.S. industry capacity increased by 2 percent in 1989. The FRS companies' heavy/sour capacity fell even more sharply, by 9 percent to 4.5

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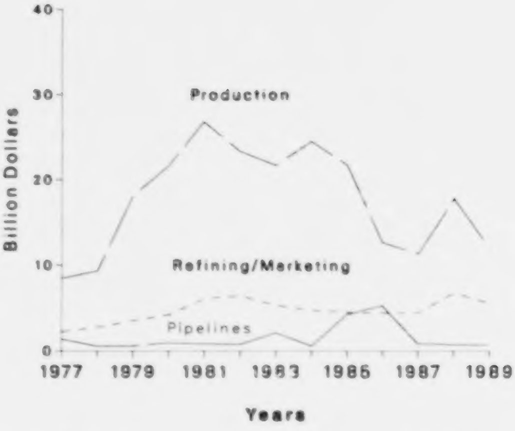
[46] Compiled from companies' annual reports to stockholders.

million barrels per day, while U.S. industry heavy/sour capacity increased by 2 percent to 5.8 million barrels per day. For FRS companies overall, there was reduced capability to produce higher octane gasoline and to process lower quality crude oil (Table 29).

Most FRS companies have refinery projects underway to increase downstream processing capabilities. Some examples include the following:

- American Petrofina began construction of $150 million fuel products project at Port Arthur, Texas;
- Ashland expects to spend $200 million over the next 3 years for distillate desulfurizers and sulfur recovery capacity;
- Chevron is spending $100 million to upgrade two units at Port Arthur, Texas to convert more heavy distillates into gasoline, and plans are underway for a $1 billion modernization of its Richmond, California refinery;
- Sun Company has a $126 million expansion of its Philadelphia refinery underway and added a $45 million reformer to its Puerto Rico refinery.

Figure 14. Additions to Investment in Place in U.S. Petroleum for FRS Companies, 1977-1989



Note: Merger purchase values are excluded from 1982 and 1984 data.
Source: Energy Information Administration, Form EIA-28.

Table 28. U.S. Downstream Refining Capacity for FRS Companies Ranked by Total Energy Assets, and U.S. Industry, 1987-1989
(Thousand Barrels per Day)

Company Group	Octane/Unleaded Boosting Capacity[a]				Heavy/Sour Crude Capacity[b]			
	1987	1988	1989	Percent Change 1988-1989	1987	1988	1989	Percent Change 1988-1989
Top Four	3,455	3,537	3,069	-13.2	1,944	2,136	1,855	-13.2
Five Through Twelve	3,760	3,737	3,589	-4.0	1,752	1,832	1,664	-9.2
All Other	1,916	1,809	1,804	-0.3	996	960	955	-0.5
All FRS	9,132	9,082	8,463	-6.8	4,692	4,928	4,473	-9.2
U.S. Industry	11,481	11,528	11,783	2.2	5,415	5,712	5,800	1.5
FRS Share (percent)	79.5	78.8	71.8	--	86.6	86.3	77.1	--

[a] Includes catalytic reforming, fresh feed catalytic cracking, hydrocracking, and alkylation capacities in thousand barrels per stream day.

[b] Includes hydrotreating and hydrorefining capacities exclusive of pretreated catalytic reformer feed, naphtha desulfurization, and naphtha olefin or aromatics saturation in thousand barrels per stream day.

-- = Not applicable.

Note: Sum of components may not equal total due to independent rounding.

Sources: Energy Information Administration, *Petroleum Supply Annual 1989*, DOE/EIA-0340(89)/1 (Washington, DC, May 1990) and previous editions and *Oil and Gas Journal* (Tulsa, OK, March 30, 1987; March 21, 1988; March 20, 1989; and March 26, 1990).

Table 29. Downstream Refining Capacity as a Percentage of Distillation Capacity for FRS Companies and U.S. Industry, 1982-1989
(Percent)

Type of Capacity/Group	1982	1983	1984	1985	1986	1987	1988	1989
Octane/Unleaded Boosting[a]								
FRS Companies								
Top Four	69.2	70.3	73.4	69.5	72.6	72.1	76.0	76.3
Five Through Twelve	66.8	71.6	72.5	73.5	75.5	77.7	75.7	74.5
All Other	65.8	63.1	60.2	66.7	68.3	67.7	67.2	68.1
All FRS	67.3	68.6	69.3	70.4	72.7	73.3	74.0	73.7
U.S. Industry	64.4	65.1	67.2	68.4	69.9	69.2	70.8	72.6
Heavy/Sour Crude[b]								
FRS Companies								
Top Four	35.9	39.7	41.5	39.0	41.1	40.6	45.9	46.1
Five Through Twelve	29.1	35.6	34.8	32.8	38.5	36.2	37.1	34.5
All Other	28.7	31.9	33.4	34.8	35.4	35.2	35.7	36.0
All FRS	31.2	35.8	36.7	35.7	38.8	37.7	40.1	38.9
U.S. Industry	26.7	29.1	32.0	32.9	33.9	32.7	35.1	35.7

[a] Includes catalytic reforming, fresh feed catalytic cracking, hydrocracking, and alkylation capacities.

[b] Includes hydrotreating and hydrorefining capacities exclusive of pretreated catalytic reformer feed, naphtha desulfurization, and naphtha olefin or aromatics saturation.

Sources: FRS companies' crude distillation capacity: Energy Information Administration, Form EIA-28.

Other capacities: Energy Information Administration, *Petroleum Supply Annual 1989*, DOE/EIA-0340(89)/1 (Washington, DC, May 1990) and previous editions and *Oil and Gas Journal* (Tulsa, OK, March 21, 1983; March 26, 1984;

March 18, 1985; December 30, 1985; March 24, 1986; December 22/29, 1986; March 30, 1987; March 21, 1988; March 20, 1989, and March 26, 1990).

Several FRS companies, e.g., Amerada Hess, Ashland, Atlantic Richfield, and Phillips, are adding or expanding methyl tertiary butyl ether (MTBE) units at their refineries. These units produce a high-octane gasoline component used to blend midgrade and premium gasolines and which also is a key ingredient in many reformulated gasolines. Currently FRS companies are estimated to have 73 percent of U.S. MTBE capacity of 126,500 barrels per day.[47] Atlantic Richfield alone is estimated to have over one-third of U.S. MTBE capacity. The company has stated that it is the world's largest producer of MTBE.[48]

Changing Product Mix

Production of leaded gasoline fell sharply for U.S. refiners in 1989. At least two FRS companies, Ashland and Phillips, ceased leaded gasoline production entirely. Increasingly stringent environmental restrictions and the additional cost incurred to maintain a separate storage system for leaded gasoline made production unprofitable for most refiners. As result, U.S. output of leaded gasoline fell by 41 percent to 763 thousand barrels per day.[49] Presumably, many former consumers of leaded turned to unleaded gasoline grades in 1989. For example, the 546 thousand barrel per day increase in unleaded output almost exactly matched the 539 thousand barrel per day fall in leaded output.

Total U.S. sales of premium gasoline (octane greater than 90) fell from 76.8 million gallons per day in 1988 to 74.8 million gallons per day in 1989.[50] This was the first fall in premium sales volume since at least 1983. Increased prices and the growth of midgrade gasoline sales (octane from 88 to 90) caused the fall in premium sales volume, which tends to be more price sensitive than do other grades. In 1989, midgrade and regular gasoline accounted for 8 percent and 66 percent, respectively, of unleaded sales.[51] There is a tradeoff in the production of high-octane gasoline such that with increased octane, the yield of gasoline falls.[52] This can be seen in the fall in the gasoline yield from 47.4 percent in 1983 to 45.7 percent in 1989.[53]

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[47] *Octane Week*, August 27, 1990, p. 8.

[48] ARCO, *Annual Report 1989*, p. 29.

[49] Energy Information Administration, *Petroleum Supply Annual 1988*, DOE/EIA-0340(88)/1 (Washington, DC, May 1989), Table 3 and *Petroleum Supply Annual 1989*, DOE/EIA-0340(89)/1 (Washington, DC, May 1990), Table 3.

[50] Energy Information Administration, *Petroleum Marketing Monthly*, June 1990, DOE/EIA-0380(90/06) (Washington, DC, September 1990), Table 12.

[51] Energy Information Administration, *Petroleum Marketing Monthly*, June 1990, DOE/EIA-0380(90/06) (Washington, DC, September 1990), Table 12. Note that data for midgrade gasoline only became available in 1989.

Federal air quality regulations mandated that the Reid Vapor Pressure (RVP) of gasoline not exceed 10.5 pounds per square inch (9 pounds in some areas) between June 1 and September 15. The objective was to reduce low-level ozone by reducing emissions of volatile organic compounds from automobile exhausts. However, achieving lower RVP required refiners to use higher cost substitutes, such as MTBE, for butane in gasoline blending.[54] Higher gasoline prices are required to recover these increased costs and maintain profit margins.

Several FRS companies have introduced reformulated gasoline, which typically uses additional volumes of MTBE in blending, in some of their marketing areas. Reformulated gasoline is intended to be more environmentally benign without sacrificing engine performance. Atlantic Richfield, for example, introduced a reformulated gasoline tailored for use with older automobiles that use leaded gasoline.

Marketing Developments

Total gasoline sales fell 6 percent for the FRS companies (Table 30). However, sales through the FRS companies' direct marketing network, i.e., through dealer-operated and company-operated outlets increased by 4 percent in 1989. Thus, the fall in volume was concentrated at the wholesale, jobber level. The wholesale class of trade accounted for 43 percent of volume in 1989 compared with 45 percent in 1988. Within the FRS companies' retail marketing networks, sales volume also shifted slightly. Company-operated volume accounted for 32 percent of retail sales in 1989 compared with 31 percent in 1988.

Largely due to the changes in ownership in 1989, the number of FRS outlets fell sharply. Total gasoline outlets fell by 19 percent to 53,584 in 1989. Dealer-operated outlets fell by 23 percent to 42,589 while company-operated outlets increased by 3 percent to 10,995. Consequently, company-operated outlets accounted for 21 percent of total FRS outlets in 1989 compared with 16 percent in 1988. There may be a trend toward more company-operated outlets. For example, Phillips Petroleum, a company that traditionally has emphasized sales to jobbers, added 27 company-operated outlets in 1989. Phillips reported that it "... remains committed to increasing gasoline sales through company-operated, retail service stations."[55] The company also stated while only 3 percent of its outlets were company operated, they generated 13 percent of sales.

As a result of the relatively steady volume of sales and the sharp fall in the number of stations, average outlet volume increased dramatically. Average outlet volume is an important indicator of outlet viability. Average monthly gasoline sales at dealer-operated outlets increased by 35 percent to 63 thousand gallons. Some companies reported much larger average volumes. For example, in its annual report to stockholders, Atlantic Richfield reported that its dealers averaged 213 thousand gallons per month.[56] The average at FRS company-operated outlets increased slightly to 113 thousand gallons per month.

In the last 2 years, the FRS companies have invested $5.6 billion in their marketing operations (Table 6). Most FRS companies have undertaken projects to upgrade their retail networks. One of the largest such projects has been undertaken by Chevron. The company has started a $1.5 billion program of service station remodeling and construction, while planning to reduce the number of company-owned and leased stations from 3,000 to 2,500.[57]

Environmental factors have become more prominent in gasoline marketing than ever before. The status of underground storage tanks, and the requirement to replace large numbers of substandard tanks, has prompted part of the high level of marketing investment and operating expense. In part, FRS companies' marketing expenses reflected these costs. The overall FRS marketing expense per barrel increased from $1.57 in 1988 to $1.82 in 1989 (Table 31). All three FRS size groups reported increased marketing expense per barrel in 1989.

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[52] Robert W. Vagnetti, "Economics of Gasoline Pool Octane Growth," Energy Information Administration, *Petroleum Marketing Monthly*, March 1990, DOE/EIA-0380(90/03) (Washington, DC, June 1990), p. 15.

[53] The refinery yield is total finished motor gasoline output minus net input of motor gasoline blending components, minus input of natural gas plant liquids, other hydrocarbons, and alcohol divided by crude oil inputs and net reruns of unfinished oils. Energy Information Administration, *Petroleum Supply Annual 1983*, DOE/EIA-0340(83)/1 (Washington, DC, June 1984), Table 13 and *Petroleum Supply Annual 1989*, DOE/EIA-0340(89)/1 (Washington, DC, May 1990), Table 19.

[54] Energy Information Administration, *Petroleum Supply Monthly*, June 1990, DOE/EIA-0109(90/06) (Washington, DC, August 1990), pp. xviii-xix.

[55] Phillips Petroleum Company, *Annual Report 1989*, p. 14.

[56] ARCO, *Annual Report 1989*, p. 25.

[57] Chevron, Inc., *Annual Report 1989*, p. 19.

Table 30. Gasoline Distribution by FRS Companies, 1986-1989

Distribution Category	1986	1987	1988	1989	Percent Change 1988-1989
	(million barrels)				
Wholesale Volume	1,172.5	1,109.4	1,106.8	1,006.6	-9.1
Retail Volume					
Dealer Volume	687.4	718.1	741.8	767.8	3.5
Company-Operated Volume	311.8	318.1	340.2	355.6	4.5
Total Retail Volume	999.2	1,036.2	1,082.0	1,123.4	3.8
Direct Volume	162.6	244.6	262.1	183.6	-30.0
Intersegment Volume	8.0	8.4	8.7	11.6	32.7
Total Volume	2,342.3	2,398.7	2,459.6	2,325.1	-5.5
	(number of outlets)				
Dealer Outlets	54,233	51,382	55,488	42,589	-23.2
Company-Operated Outlets	9,327	9,837	10,712	10,995	2.6
Total Retail Outlets	63,560	61,219	66,200	53,584	-19.1
	(thousand gallons per month)				
Average Monthly Outlet Volume					
Dealers	44	49	47	63	34.9
Company Operated	117	113	111	113	1.8
All Retail	55	59	57	73	28.3

Note: Sum of components may not equal total due to independent rounding. Percent change calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Table 31. Marketing Characteristics and Refined Product Margin for FRS Companies Ranked by Total Energy Assets, 1988-1989

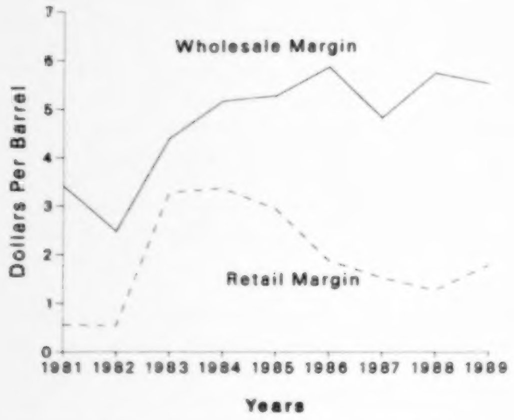
Group	Average Outlet Volume (thousand gallons per month)		Margin Per Barrel (dollars per barrel)		Marketing Expense Per Barrel (dollars per barrel)		Standard Deviation of Marketing Expense Per Barrel (dollars per barrel)	
	1988	1989	1988	1989	1988	1989	1988	1989
Top Four	46	71	1.51	0.08	2.44	2.56	1.14	1.71
Five Through Twelve	108	109	2.41	3.06	1.32	1.57	0.58	0.55
All Other	36	47	1.12	0.83	0.70	1.23	0.63	0.89
All FRS	57	73	1.78	1.48	1.57	1.82	1.07	1.28

Source: Energy Information Administration, Form EIA-28.

All three FRS size groups reported increased average outlet volume (Table 31). The 5 through 12 group continued to have, by far, the largest average outlet volume of 109 thousand gallons per month, compared with 71 thousand and 47 thousand for the top four and all other groups, respectively. There remained large differences in refined product margins among the three FRS groups. For example, the five through twelve group's refined product margin was substantially higher than for the other two groups. It is noteworthy that this group's average outlet volume also was substantially higher than for the other groups.

These volume increases did not come at the expense of lower retail margins. Indeed, the average retail margin, the difference between the retail price and the dealers' buying price, increased for the first time since 1984 (Figure 15). Typically, the wholesale margin, the difference between the retail price and the wholesalers'

Figure 15. Retail and Wholesale Gasoline Margins, 1981-1989



Source: Energy Information Administration, Form EIA-28.

buying price, is larger than the retail margin since the wholesale class of trade provides facilities and services that retailers do not. In 1989, the wholesale class of trade's volume (Table 30) and margin fell (Figure 15). However, the margin remained relatively high compared with the rest of the 1980's.

Rate-Regulated Pipelines

The rate-regulated pipeline segment has been the most profitable U.S. petroleum segment throughout most of the 1980's (Figure 12). However, the trend is obscured by the departure of Tenneco, Inc. from the FRS. Tenneco disposed of its non-pipeline energy assets in late 1988 and thereby no longer qualified to be an FRS company. The departure of Tenneco largely explains the 23-percent fall in income to $1.9 billion (excluding unusual items) in 1989 (Table 22). Liquids pipelines continued to be more profitable than natural gas pipelines (Table 32).

Even though rate-regulated pipelines continue to be relatively profitable, this segment attracts modest capital expenditures. Capital expenditures in 1989 were typical in this regard, as additions to investment in place fell by 0.3 percent to $700 million (Table 23). Consequently, new investment failed to keep pace with DD&A which caused net investment in place to decline slightly (Table 33).

Excluding Tenneco and unusual items, net income from FRS companies' rate-regulated pipeline operations declined 16 percent in 1989. However, financial results differed between natural gas pipelines and oil pipelines. In tracing the performance of the rate-regulated pipeline segment of FRS operations, natural gas pipelines and oil pipelines are considered separately.[58] By making this separation, a distinction can be drawn between those factors which affected natural gas pipelines and those which affected oil pipelines.

Between 1988 and 1989, excluding Tenneco, FRS natural gas pipeline revenues fell 11 percent. (The tables in this chapter include data for Tenneco prior to 1989. However, when year-to-year comparisons are made the data are adjusted to exclude Tenneco to the extent feasible.) All three FRS natural gas pipeline companies (Burlington Resources, Coastal Corp., and Occidental Petroleum) reported declines in net income in 1989. In total, this decline amounted to 2 percent after excluding unusual items. For the year, FRS gas pipelines realized a 5 percent rate of return. The continued movement away from direct gas sales to the offering of transportation services may have harmed the financial performance of FRS gas pipelines in 1989, as transportation has proven to be a less productive generator of income for pipeline companies. For FRS gas pipeline companies the ratio of transportation to sales increased in 1989.[59]

This change in natural gas pipeline orientation was mostly a result of recent regulatory developments. Traditionally, gas pipelines have acted primarily as suppliers of bundled gas services. Pipeline companies would purchase gas from producers, ship the same gas to end users, and ultimately charge end users for both the marketing and transporting of this gas. In response to market and regulatory changes due, for example, to the Natural Gas Policy Act of 1978 and Federal Energy Regulatory Commission decisions No. 436 and No. 500, gas pipelines have increasingly separated these two operations.[60] This separation has allowed end users

[58] This separation can be accomplished because, in their pipeline operations, FRS companies are either primarily engaged in natural gas transmission or liquids transport. In 1989, all FRS companies were engaged in some form of pipeline activity. However, three companies were highly specialized in natural gas pipelines, while the remaining FRS companies' rate-regulated pipelines were primarily liquids (i.e., crude oil and refined products) pipelines. The three companies primarily engaged in natural gas pipelines accounted for over half of the FRS companies rate-regulated pipeline investment in place and 98 percent of the natural gas pipeline investment in place.

[59] 1989 *10K Reports* for Burlington Resources, Coastal Corp, and Occidental Petroleum, pp. 5, 3, and 5, respectively.

[60] Order 436 permitted non-discriminatory open access gas transmission on interstate natural gas pipelines. In essence this order stated that if a pipeline became an open-access carrier, customers of the pipeline were allowed to restructure their contractual obligations with that pipeline and negotiate directly with gas marketers or gas producers. Order 500 replaced Order 436 and added a provision for pipelines to be compensated for take-or-pay liabilities if they become open access carriers. After January 1988, such pipelines received take-or-pay credits for transporting a producer's gas.

to negotiate directly with producers for gas supplies, thereby bypassing the marketing operations of natural gas pipelines. Under current regulatory authority, pipelines that become open access carriers are mandated to offer non-discriminatory transportation services to all shippers including competitors. As a result, transportation volume has soared while gas sales have diminished considerably. Carriage (transportation volume), which was negligible before 1984, by 1989 amounted to 71 percent of all natural gas delivered for the market.[61]

On the cost side of the ledger, the special charges FRS gas pipelines took against earnings to settle take-or-pay obligations resulted in a rise in operating expenses.[62]

Table 32. Financial Items for Rate-Regulated Pipelines for FRS Companies, 1984-1989
(Billion Dollars)

Financial Items	1984	1985	1986	1987	1988	1989
Natural Gas Pipelines[a]						
Revenues						
Transport	5.2	6.2	7.9	5.4	4.8	4.5
Other	4.5	4.0	3.3	3.9	4.2	1.0
Total	9.7	10.2	11.2	9.3	9.0	5.5
Operating Expenses						
General Operating and Administrative Expenses[b]	8.5	8.6	9.1	7.7	8.1	7.6
DD&A	0.3	0.4	0.5	0.5	0.6	0.4
Total[b]	8.8	9.0	9.6	8.2	8.5	4.9
Operating Income[b]	0.9	1.2	1.6	1.1	0.5	0.8
Additions to Investment in Place[c]	0.2	3.9	5.1	0.3	0.4	0.4
Rate of Return[d](percent)	17.7	9.4	7.0	6.6	1.6	4.6
Liquids Pipelines[e]						
Revenues						
Transport	5.1	5.0	4.8	4.7	4.5	4.0
Other	0.1	0.7	0.5	0.4	0.5	0.6
Total	5.3	5.7	5.3	5.2	4.9	4.6
Operating Expenses						
General Operating and Administrative Expenses[b]	1.5	2.2	1.8	1.7	1.9	2.1
DD&A	0.5	0.5	0.5	0.6	0.6	0.6
Total[b]	2.0	2.7	2.2	2.2	2.4	2.2
Operating Income[b]	3.3	3.0	3.0	2.9	2.5	2.0
Additions to Investment in Place[c]	0.6	0.4	0.3	0.6	0.3	0.3
Rate of Return[d](percent)	22.1	19.8	22.1	20.7	20.4	16.5

[a] Data are for FRS companies with pipeline assets primarily in natural gas transmission.
[b] Excludes special charges taken by FRS pipeline operators primarily to settle take-or-pay obligations.
[c] Measured by additions to property, plant, and equipment (PP&E) plus additions to investments and advances.
[d] Net income as a percent of net PP&E and investments and advances to unconsolidated affiliates.
[e] Data are for FRS companies with pipeline assets primarily in liquids pipelines.
Note: Sum of components may not equal total due to independent rounding. Percent change calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

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[61] Interstate Natural Gas Association of America, Rate and Policy Analysis Department, *Carriage Through 1989*, (Washington, DC, April 1990), Table A1.

[62] Take-or-Pay contracts require that a predetermined amount of gas be paid for, even if not taken.

Table 33. Net Investment in Place in U.S. Regulated Pipelines for FRS Companies Ranked by Total Energy Assets and Pipeline Type, 1984-1989
(Billion Dollars)

Net Investment in Place[a]	1985	1986	1987	1988	1989	Percent Change 1988-1989
U.S. Pipelines						
Top Four	2.7	2.6	2.6	2.7	2.7	-0.3
Five Through Twelve	5.1	9.7	10.5	11.3	10.9	-3.9
All Other	7.7	7.4	7.1	6.6	5.2	-21.8
All FRS	15.4	19.8	20.2	20.6	18.7	-9.2
Type of Pipelines						
Crude Oil and Liquids	7.0	6.7	7.6	7.3	7.2	-1.5
Refined Products	1.1	1.1	1.2	1.3	1.3	-1.7
Natural Gas	7.4	11.9	11.5	12.0	10.2	-14.7

[a] Defined as the sum of net PP&E and investments and advances to unconsolidated affiliates.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

The degree to which natural gas pipelines have adopted the offering of carriage services has been determined in part by their take-or-pay exposure. Take-or-pay obligations first became a problem after 1983 when rising wellhead prices reduced natural gas demand. A lingering oversupply of gas has existed since, causing pipeline operators to accumulate billions of dollars in these obligations. As of October 31, 1990, $9.1 billion in take-or-pay settlement costs had been paid by 23 major interstate pipeline customers to their producers. Further, evidence suggests that take-or-pay obligations will have a negative impact upon gas pipeline profits beyond 1990, although this impact should lessen over time. As of September 1989, in a survey of 24 major gas pipelines, it was estimated that $2.3 billion of exposure remained.[63] In 1989, Occidental took a $193 million take-or-pay related charge against operating income.[64] In 1989, the other two FRS gas pipeline companies continued to maintain reserves against such charges in the future.

FRS oil pipeline income declined 20 percent in 1989 on a 37-percent decline in revenue. This resulted in FRS oil pipelines earning a 17-percent rate of return in 1989 (Table 32). This rate of return for FRS oil pipelines was the lowest since FRS data has been collected. The financial performance of the oil pipeline operations of the FRS companies was negatively affected by an 8-percent decline in throughput on the Trans Alaska Pipeline (TAPS).[65] A large part of FRS oil pipeline revenue is generated by TAPS. This fall in TAPS throughput was due both to a pipeline shutdown related to the *Exxon Valdez* spill as well as to declining North Slope production. For example, Alaska oil production declined 8 percent in 1989.[66]

Due to earlier than expected corrosion problems, in 1990 the owners of TAPS[67] will spend $600 million to $1.5 billion to replace and repair rusting pipes. This additional maintenance will also involve intermittent TAPS shutdowns and a temporary decline in TAPS throughput. In October 1990, the owners of TAPS also announced a plan to invest over $1 billion in additional gas handling facilities on Alaska's North Slope. The purpose of these facilities would be to provide additional gas pressure to North Slope oil fields thus abating recent declines in well production. The additional gas handling facilities are expected to increase North Slope production by 100,000 barrels a day starting in 1995 and will result in the recovery of additional liquids in the range of 330-450 million barrels of oil over the life of the field.[68]

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[63] Interstate Natural Gas Association of America, Rate and Policy Analysis Department, *Take-or-Pay Exposure and Costs Through September 30, 1989* (Washington, DC, December 1989) p. 1.

[64] Occidental Petroleum Corporation, *Annual Report 1989*, p. 62.

[65] ARCO, *Annual Report 1989*, p. 26.

[66] Energy Information Administration, *Monthly Energy Review June 1990*, DOE/EIA-0035(90/06), (Washington, DC, September 1990), Table 3.2A.

[67] The following FRS companies have together a 100 percent holding in the Trans Alaska Pipeline: BP America Inc., Atlantic Richfield Company, Exxon Corporation, Mobil Corporation, Unocal Corporation, Phillips Petroleum Company, and Amerada Hess Corporation. Source: *Oil and Gas Journal*, (Tulsa, OK, November 28, 1988), p. 60.

[68] BP America, *News*, (Cleveland, OH, October 9, 1990).

5. United States Petroleum Resource Development

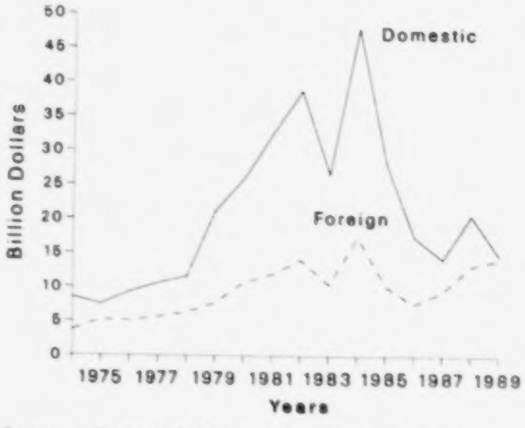
As a result of reduced U.S. exploration and development activity following the general decline in energy prices since 1981, oil and gas reserve additions in the United States generally have not kept pace with production. While prices did rebound somewhat in 1987, prices began to slip by late 1988. The industry responded to this price decline by reducing 1989 exploration and development budgets. Indicative of this, the Hughes rig count, a measure of industry activity, fell to its lowest annual level on record, averaging 869 for the year. As the year unfolded, however, oil prices rose to $17 per barrel, the highest monthly price since early 1986. As a result, oilfield activity turned around as the year progressed. By December 1989, the monthly rig count, standing at just 753 in March, had risen 41 percent to 1,065.[69]

The uncertainty over oil prices at the end of 1988 caused the FRS companies to cut back on most fronts in 1989. Overall, their U.S. exploration and development expenditures declined 29 percent, to $15 billion. FRS company well completions fell 20 percent, almost twice the rate of decline suffered by the rest of the U.S. industry. End-of-year reserves and reserve additions declined once again for the FRS companies as well as for the overall U.S. oil and gas industry. Lifting costs rose somewhat, while the cost of finding oil and gas fell. The FRS companies' combined U.S. oil and gas production declined 6 percent, continuing a trend seen throughout the 1970's and 1980's.

Although the overall picture for U.S. exploration and development dimmed in 1989, some segments fared better than in 1988. Offshore development expenditures and activity increased over the previous year. With an end to the "gas bubble"[70] in sight, and the positive impacts of price decontrol, gas drilling continued on the upward trend started in 1988. New production and drilling technologies, such as horizontal drilling, played greater roles for some FRS companies, as efforts to boost production and cut costs continued to be pursued.

Perhaps the most telling development, however, is shown by a comparison between the FRS companies' domestic and foreign exploration and development expenditures. While domestic expenditures have continued to decline, foreign expenditures surpassed the levels attained prior to the 1986 oil price collapse (Figure 16). The FRS companies continued to scale back their domestic activity, and emphasize their foreign operations. Domestic exploration and development expenditures equaled only 51 percent of total FRS exploration and development expenditures in 1989 as compared to 74 percent in 1985. This trend reflects expectations of lower finding costs, potentially greater finds, and higher rates of return on operations outside the United States.

Figure 16. FRS Companies' Domestic and Foreign Exploration and Development Expenditures, 1974-1989



Source: Energy Information Administration, Form EIA-28.

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[69] Source: Energy Information Administration, *Monthly Energy Review*, June 1990, DOE/EIA-0035(90/06) (Washington, DC, September 1990), p. 64.

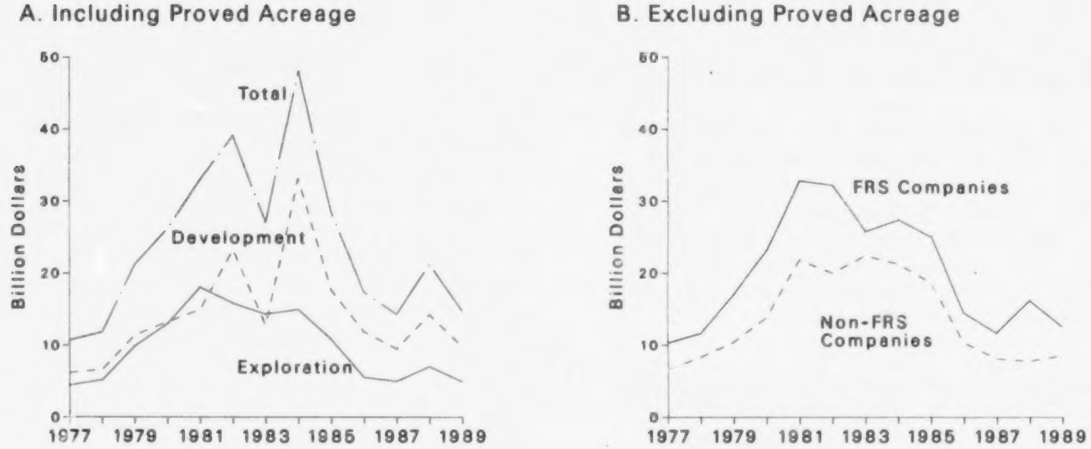
[70] "Gas bubble" is the term used to describe the historically high excess of U.S. natural gas deliverability over U.S. natural gas consumption which began in 1982.

Exploration and Development Expenditures

Compared with all of the 1980's, 1989 was a year of decreased domestic expenditures in nearly all areas for the FRS companies. Total expenditures fell 29 percent to $15.0 billion, with $4.9 billion spent on exploration and $10.1 billion spent on development (Figure 17). Excluding proved acreage acquisitions, U.S. exploration and development spending by the FRS companies fell 20 percent to $12.8 billion. By contrast, the level of spending for the non-FRS companies increased 7 percent to $8.5 billion (Figure 17). During the same period, U.S. gross private domestic nonresidential investment rose 5 percent (Table 34).

FRS spending was down for both onshore and offshore sectors (Table 35). Offshore expenditures fell 26 percent to $6.0 billion and onshore expenditures fell 31 percent to $9.0 billion. The only areas to show any increase over the previous year were offshore lease equipment and offshore development drilling expenditures. Spending on offshore lease equipment rose 49 percent, while offshore development drilling and equipping rose 23 percent. The increased spending in these two areas coupled with the falloff in spending for offshore exploration indicate that FRS companies were concentrating on the development of current offshore leases, while scaling back exploration. Companies were under pressure in 1988 to drill exploratory wells on leases due to expire.[71] By 1989 they had sunk holes on most of those leases and were switching their efforts towards lease development.

Figure 17. **U.S. Exporation and Development Expenditures for FRS Companies and Non-FRS Companies, 1977-1989**



Sources: FRS Companies. Energy Information Administration, Form EIA-28. Non-FRS Companies: U.S. industry total less FRS total. Industry totals for 1977 through 1982: U.S. Bureau of the Census, Current Industrial Reports Series, *Annual Survey of Oil and Gas, 1982* (Washington, DC, March 1984). Industry totals for 1983 through 1989: American Petroleum Institute, *1989 Survey on Oil and Gas Expenditures* (Washington, DC, November 1990).

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[71] Etienne Deffarges and Robert C. Moeller, "No Growth Expected in Gulf of Mexico Exploration and Development Spending," *Oil and Gas Journal*, (September 1989), pp 69-78.

Table 34. U.S. Exploration and Development Expenditures Compared to Various Measures of Economic Activity, 1987-1989
(Billion Dollars)

Expenditures and Economic Activity	1987	1988	1989	Percent Change 1988-1989
Exploration and Development Expenditures, FRS Companies	14.3	21.0	15.0	-28.7
Exploration and Development Expenditures Excluding Expenditures for Proved Acreage Acquisition, FRS Companies	11.6	16.0	12.8	-19.7
Exploration and Development Expenditures, U.S. Industry[a]	19.8	24.0	21.4	-10.9
Gross National Product	4,515.6	4,873.7	5,200.8	6.7
Gross National Product[b] (1982 Dollars)	3,845.3	4,016.9	4,117.7	2.5
Gross Private Domestic Investment, Nonresidential	444.9	488.4	511.9	4.8

[a] Excludes expenditures for proved acreage acquisition.

[b] Constant dollar amounts were computed using the GNP implicit price deflator.

Sources: FRS companies: Energy Information Administration, Form EIA-28. U.S. industry exploration and development expenditures: American Petroleum Institute, *1989 Survey on Oil & Gas Expenditures* (Washington, DC, November 1990).

Gross national product and gross private domestic investment: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, July 1990).

Table 35. Disaggregated U.S. Exploration and Development Expenditures for FRS Companies, 1988-1989
(Billion Dollars)

Expenditure Category	Onshore			Offshore			Total		
	1988	1989	Percent Change	1988	1989	Percent Change	1988	1989	Percent Change
Exploration									
Acquisition of Unproved Acreage	1.1	0.6	-42.5	1.2	0.4	-65.5	2.4	1.1	-54.7
Geological and Geophysical	0.6	0.4	-33.9	0.3	0.3	0.0	1.0	0.7	-22.1
Drilling and Equipping	1.0	0.8	-25.7	1.3	1.1	-11.6	2.3	1.9	-17.9
Other	1.0	0.7	-32.0	0.5	0.5	20.1	1.5	1.2	-15.6
Subtotal	3.7	2.5	-33.7	3.3	2.4	-26.4	7.0	4.9	-30.3
Development									
Acquisition of Proved Acreage	2.5	1.2	-49.8	2.6	0.9	-63.9	5.0	2.2	-57.0
Lease Equipment	1.5	1.2	-18.5	0.6	0.8	48.7	2.0	2.0	0.3
Drilling and Equipping	2.7	2.5	-7.3	1.1	1.3	22.9	3.8	3.8	1.4
Other	2.6	1.6	-38.9	0.5	0.5	-13.1	3.1	2.0	-34.4
Subtotal	9.2	6.5	-29.4	4.8	3.6	-24.9	14.0	10.1	-27.8
Exploration and Development Total	12.9	9.0	-30.5	8.1	6.0	-25.5	21.0	15.0	-28.7

Note: Sum of components may not equal total due to independent rounding. Percent changes are based on unrounded data.
Source: Energy Information Administration, Form EIA-28.

Drilling Activity

Natural Gas - Rising Prospects

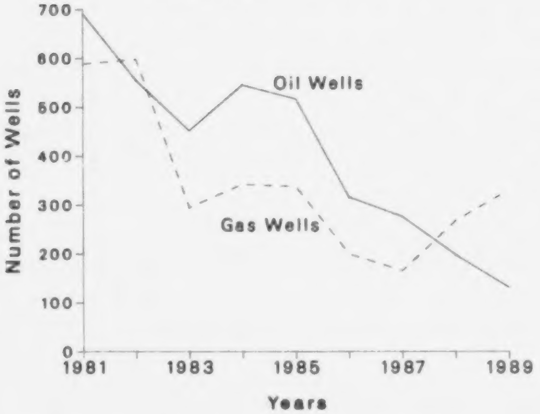
The years 1988 and 1989 evidenced a fundamental shift in the drilling priorities of the FRS companies and the industry as a whole away from oil and towards gas. Emphasis on gas drilling is traceable to the generally optimistic outlook for gas prices. While current prices are considered abnormally low by many producers, based on the relative energy content of gas compared to alternative energy sources, the "gas bubble" which has depressed prices for several years appears to be dissipating. Producers are gearing up for anticipated price rises by drilling for new supplies, seeking new markets, and promoting natural gas as a clean and efficient fuel for the future.

Exploratory gas completions for the FRS companies, up 24 percent in 1989, were over twice as numerous as oil completions (Figure 18). A similar recent upward trend can be seen in natural gas development drilling (Figure 19). For the industry as a whole, exploratory gas completions were nearly unchanged while oil exploratory completions posted a 29-percent decline. Industry oil development completions were down 22 percent, and industry gas development completions were up 14 percent (Table 36).

Drilling of development wells offshore was the only other area that showed increased activity by the FRS companies in 1989 (Table 37). By contrast, offshore exploratory drilling registered the largest relative decline. Offshore exploratory completions were boosted in 1988 by the need to fulfill drilling commitments on leases before they expired. By 1989, most of the obligations for the timely exploratory drilling of offshore leases had been met, and FRS companies moved from exploratory to development drilling.

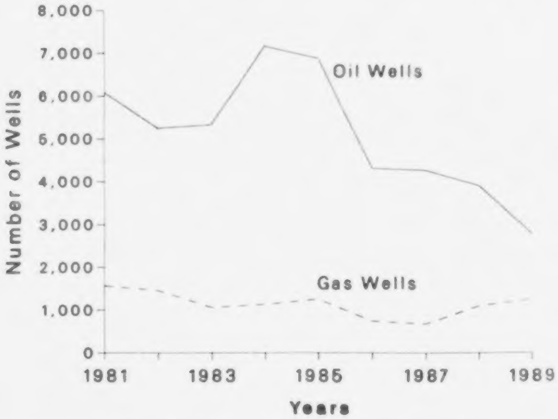
Although oil prices rose between 1988 and 1989, they still remained well below pre-1986 levels. The low level of oil prices of recent years has been a deterrent to oil drilling. The downward trend in oil drilling by the FRS companies (Figures 18 and 19) continued in 1989 (Table 37) and largely accounted for the overall 20-percent decline in the FRS companies' U.S. well completions in 1989 (Table 38).

Figure 18. Exploratory Oil and Gas Wells Completed for FRS Companies, 1981-1989



Source: Energy Information Administration. Form EIA-28.

Figure 19. Development Oil and Gas Wells Completed for FRS Companies, 1981-1989



Source: Energy Information Administration, Form EIA-28.

Table 36. Successful Well Completions for FRS Companies and U.S. Industry, 1986-1989

Well Completions	1986	1987	1988	1989	Percent Change 1988-1989
FRS Companies					
Exploratory					
Oil	316	276	198	132	-33.3
Gas	200	167	268	331	23.5
Development					
Oil	4,309	4,259	3,903	2,765	-29.2
Gas	738	675	1,105	1,253	13.4
U.S. Industry					
Exploratory					
Oil	982	857	794	564	-29.0
Gas	729	669	664	662	-0.3
Development					
Oil	17,634	15,363	12,670	9,929	-21.6
Gas	7,384	7,076	7,701	8,797	14.2

Source: FRS Companies: Energy Information Administration, Form EIA-28. U.S. Industry: Special compilation from Energy Information Administration, Office of Oil and Gas.

Table 37. Onshore and Offshore Wells Completed and Initiated for FRS Companies, 1986-1988

Well Completions	1986	1987	1988	1989	Percent Change 1988-1989
Onshore Completions					
Exploratory	1,089	877	940	769	-18.2
Development	5,204	5,040	5,153	4,064	-21.1
Total Onshore Completions	6,293	5,917	6,093	4,833	-20.7
Offshore Completions					
Exploratory	240	172	264	189	-28.4
Development	379	252	277	285	2.9
Total Offshore Completions	619	424	541	474	-12.4
Onshore Initiations[a]					
Exploratory	871	927	871	918	5.4
Development	4,149	5,284	5,049	4,183	-17.2
Total Onshore Initiations	5,020	6,211	5,920	5,101	-13.8
Offshore Initiations[a]					
Exploratory	178	219	201	178	-11.4
Development	305	273	292	266	-8.9
Total Offshore Initiations	483	492	493	444	-9.9

[a] Measured as the number of completed wells in a year plus the number of wells in progress at the end of that year less the number of wells in progress at the end of the previous year.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Table 38. Measures of Drilling and Exploratory Activity for FRS Companies and U.S. Industry, 1986-1989

Drilling and Exploratory Activity	1986	1987	1988	1989	Percent Change 1988-1989
Exploratory and Development Wells Completed					
FRS Companies	6,913	6,341	6,634	5,306	-20.0
U.S. Industry	39,490	35,430	31,950	28,320	-11.4
Footage of Completed Wells (thousand feet)					
FRS Companies	44,037	36,252	38,506	30,607	-20.5
U.S. Industry	177,160	160,920	153,380	130,000	-15.5
Average Number of Rotary Rigs in Use	964	936	936	869	-7.2
Average Number of Seismic Crews	201	176	182	132	-27.5

Sources: FRS companies: Energy Information Administration, Form EIA-28. U.S. industry: Energy Information Administration, *Monthly Energy Review*, June 1989, DOE/EIA-0035(90/06) (Washington, DC, September 1990).

A Larger Role for New Technology

In response to low oil and gas prices and the attendant need to cut costs, new drilling and production technologies became more important to the FRS companies and the industry in the latter part of the 1980's. Horizontal drilling, infill drilling, enhanced oil recovery, and the development of unconventional gas prospects have all been employed with varying degrees of success in the past few years. Horizontal well completions expanded significantly in 1989, setting off local drilling booms in parts of Texas. Three FRS companies (Oryx Energy, Meridian Oil (a subsidiary of Burlington Resources), and Union Pacific) were particularly active, using horizontal drilling with striking success in the Pearsall Field in Texas' Austin Chalk.

Horizontal drilling allows larger areas of a hydrocarbon-bearing formation to be tapped than would otherwise be possible. Older producing wells have experienced significant boosts to production from horizontal recompletions, some recording initial increases of over 4,000 percent. For example, Oryx Energy's Panther Hollow #11 flowed at 12 barrels of oil per day (bpd) prior to a horizontal recompletion, after which it flowed at 507 bpd.[72] Although the rate of flow tends to decline after a few months, it still remains very high compared to the flow rate prior to recompletion. For example, Oryx Energy's Baggett #7 experienced a 20-fold boost in production (5 bpd to 107 bpd) after a horizontal recompletion. Almost four years later, production had fallen to 45 bpd, still a significant increase.

Horizontal completions are not cheap. The cost of completing a 7,000 foot well, with 2,500 feet of horizontal displacement in the Pearsall Field was $759 thousand.[73] A conventional completion at that depth would have cost $328 thousand.[74]

The year 1989 saw increased attention focused on gas production from unconventional sources, particularly coal-bed methane. Drilling for coal-bed methane was particularly strong in 1989, with 670 wells completed.[75] The number of producing wells increased from 730 in 1988 to 1,400 in 1989. Much of the drilling was driven by the need to lock in a tax credit of approximately 86 cents per thousand cubic feet (mcf) before the scheduled expiration on January 1, 1991. The credit is allowed on production through the year 2000 from wells drilled before the expiration date. Major areas of activity are the Black Warrior basin in Alabama and the San Juan basin in New Mexico. The FRS companies which were particularly active in drilling for coal-bed methane in 1989 were Burlington Resources and Amoco.

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[72] Guntis Moritis, "Drilling Technology," *Oil and Gas Journal*, (February 26, 1990), p. 54.

[73] Guntis Moritis, "Drilling Technology," Oil and Gas Journal, (February 26, 1990), p. 54.

[74] American Petroleum Institute, *Joint Association Survey of Drilling Costs, 1988*, (Washington, DC, December 1989).

[75] Herbert T. Black, "Update on U.S. Coalbed Methane Production," Energy Information Administration report to be published.

Likewise, FRS companies are boosting production through enhanced recovery techniques. These techniques produce oil and gas that would usually remain trapped in the reservoir. Total U.S. oil production from this source rose over 97 percent during the 1980's, from 332,821 barrels of oil per day at the start of the decade to 656,700 bpd by the end.[76] Enhanced oil recovery as a share of total U.S. production, has increased from 4 percent at the start of the decade to over 9 percent by the decade's close.

Despite the increased use of these promising technologies, they still play only a minor role in overall oilfield activity, and the impact on drilling and production statistics is slight. However, for individual FRS companies, the application of new technology can play a significant role in boosting production and lowering operating costs.

Drilling Costs Show Little Change

The overall decline in FRS spending on drilling and equipping noted earlier was mainly due to the fewer number of wells drilled. The overall cost per well rose between 1988 and 1989 by 2 percent to $857 thousand in 1989 (Table 39). This contrasts with the U.S. industry cost index which fell over 5 percent. The cost per exploratory well for the FRS companies fell 8 percent, in part because the average depth of exploratory wells decreased 11 percent, to 8 thousand feet. In contrast, there was a 9 percent increase in the cost of drilling a development well, attributable in part to an increase in the average depth by over 3 percent, to 5.3 thousand feet. When the cost per foot is used as a measure of drilling cost, average costs for exploratory and development wells rose 4 percent and 5 percent, respectively.

Table 39. Drilling Cost Indicators, FRS Companies and U.S. Industry, 1987-1989

Indicators	1987	1988	1989	Percent Change 1988-1989
Cost per Well				
Exploration and Development FRS Companies (thousand dollars)	633	844	857	1.5
Exploration, FRS Companies (thousand dollars)	1,347	1,965	1,809	-7.9
Development, FRS Companies (thousand dollars)	492	596	648	8.6
U.S. Industry Cost Index[a] (1984 = 100.0)	95.7	121.2	114.6	-5.5
Cost per Foot				
Exploration and Development FRS Companies (dollars per foot)	111	145	149	2.2
Exploration, FRS Companies (dollars per foot)	150	219	228	3.7
Development, FRS Companies (dollars per foot)	97	117	122	4.9
U.S. Industry Cost Index[a] (1984 = 100.0)	92.2	111.3	107.3	-3.5

[a] Reported cost indices are adjusted for well depth and distribution.

Note: Percent change calculated from unrounded data.

Sources: FRS companies: Energy Information Administration, Form EIA-28. Industry: Independent Petroleum Association of America, *Report of the Cost Study Committee* (Washington, DC, May 9, 1990).

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[76] Guntis Moritis, "Annual Production Report", *Oil and Gas Journal* (April 23, 1990), pp 49-82.

Lease Activity

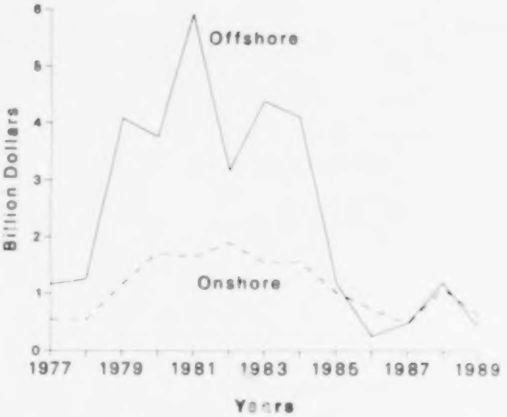
The FRS companies' reduced commitment to U.S. exploration was most evident in their spending patterns for acquisition of unproved acreage in 1989. Spending on unproved acreage fell 55 percent to $1.1 billion (Table 35). Offshore lease expenditures returned to a low level in 1989 despite the brief upturn in 1988. Spending on offshore leases fell below the amount spent on onshore leases for only the second time in the past decade (Figure 20). The FRS companies' heightened level of spending for offshore leases in 1988 was a response to the record amount of Federal Outer Continental Shelf (OCS) acreage offered for bid in that year (Table 40). In 1989, OCS offerings fell 62 percent. Nevertheless, offshore undeveloped acreage holdings continue to rise, while onshore holdings declined (Figure 21, Table 41). The amount of OCS acreage awarded fell in 1989, but at a lesser pace than lease bonuses, indicating that the cost per acre has declined (Table 40). This decline resulted from a combination of lower oil prices and the declining quality of remaining acreage.

Reserves, Reserve Additions, and Production

Oil and gas reserves are the fundamental assets of oil and gas companies, especially for large independent producers with no downstream interests. An oil and gas company is essentially self liquidating if it does not replace the reserves it produces. A company must either add reserves to continue growing at the upstream end, or at least replace the reserves which have been produced. U.S. reserves for the FRS group have been declining since the 1970's, particularly onshore (Figure 22). Consequently, the FRS companies' search for reserves has focused on more productive locales, including the offshore United States, Alaska, and foreign countries. The FRS companies are also attempting to tap additional reserves through improved recovery techniques such as enhanced oil recovery, infill drilling programs, and new drilling technology (e.g., horizontal completions).

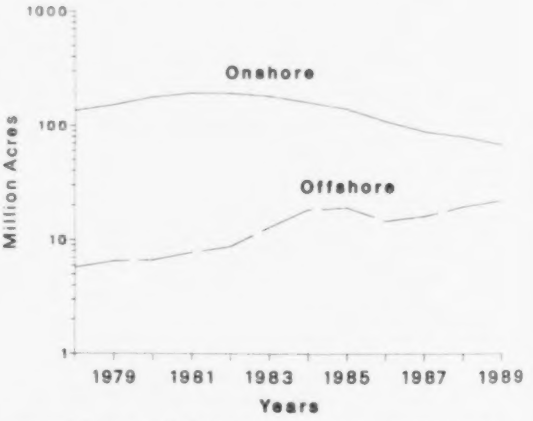
Similar trends are seen when reserve additions are compared to production. With net purchases excluded, combined oil and gas production exceeded reserve additions throughout the 1980's for the FRS companies (Table 42). The U.S. industry hardly fared much better, recording only three years, 1981, 1983, and 1988, when reserve additions exceeded production.

Figure 20. Expenditures for Acquisition of Unproved Acreage, Onshore and Offshore, for FRS Companies, 1977-1989



Source: Energy Information Administration, Form EIA-28.

Figure 21. U.S. Onshore and Offshore Undeveloped Acreage Holdings for FRS Companies, 1978-1989



Source: Energy Information Administration, Form EIA-28.

Table 40. OCS Lease Activity for the FRS Companies and U.S. Industry, 1981-1989

OCS[a] Lease Activity	1981	1982	1983	1984	1985	1986	1987	1988	1989
Acreage Offered (million acres)	7.68	7.64	119.81	154.38	87.03	58.67	59.76	157.41	60.10
Acreage Awarded (million acres)									
FRS Companies	1.70	1.35	4.75	5.14	3.17	0.56	2.40	6.81	4.14
U.S. Industry	2.27	1.89	6.59	7.49	3.51	0.73	3.45	8.13	5.58
Lease Bonuses (billion dollars)									
FRS Companies	5.29	2.53	2.33	2.73	1.38	0.13	0.32	1.05	0.40
U.S. Industry	6.65	3.99	5.75	4.04	1.54	0.19	0.50	1.21	0.65
Total Amount Bid (billion dollars)									
FRS Companies	9.86	5.78	6.19	4.25	1.42	0.16	0.41	1.40	0.49
U.S. Industry	13.67	8.68	8.03	6.48	2.24	0.23	0.65	1.65	0.86

[a] OCS = Outer Continental Shelf.

Sources: U.S. industry, 1981-1988: U.S. Department of the Interior, Minerals Management Service, *Federal Offshore Statistics: 1988* (Herndon, VA, 1990).

U.S. industry, 1989, and FRS companies: U.S. Department of the Interior, Minerals Management Service.

Table 41. Domestic Net Petroleum Acreage Under Lease for FRS Companies, 1989

Location	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Millions of Acres	Percent Change From 1988	Millions of Acres	Percent Change From 1988	Millions of Acres	Percent Change From 1988
Onshore	67.9	-15.2	32.9	-0.6	100.8	-10.9
Offshore	22.0	12.2	5.4	4.5	27.4	10.6
Total	89.9	-9.8	38.3	0.1	128.2	-7.0

Note: Percent change calculated from unrounded data.

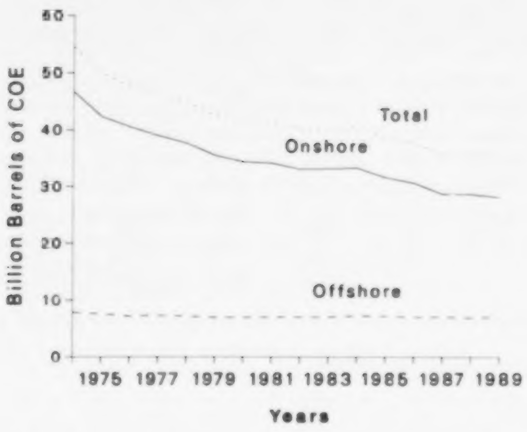
Source: Energy Information Administration, Form EIA-28.

The FRS companies' reserves, particularly onshore, declined throughout the 1970's and 1980's. In 1979, onshore oil and gas reserves equaled 35.4 billion barrels on a crude oil equivalent (COE) basis. By 1989 they had declined 21 percent to 28 billion barrels. Offshore reserves have hardly changed over the same period which served to slow the overall rate of decline. Nevertheless, the FRS companies' oil and gas reserves still declined 17.4 percent between 1979 and 1989.

Sources of Reserve Changes

The FRS companies' combined U.S. oil and gas reserve additions, excluding purchases, fell 14 percent to 2.7 billion barrels of crude oil equivalent (COE) (Table 43). This decline was a reflection of the dramatic drop off in oil well completions, since finding rates, as will be discussed later, continued to improve. Total industry reserve additions registered an even greater decline, down 25 percent to 5.4 billion barrels of COE. The FRS companies replaced 83 percent of their U.S. oil and gas production through reserve additions (excluding purchases and sales of reserves) in 1989 which was close to the 85-percent replacement rate for the industry overall.

Figure 22. End-of-Year U.S. Oil and Gas Reserves for FRS Companies, 1974-1989



Source: Energy Information Administration, Form EIA-28.

Oil Reserve Additions Fall Short of Production

Although oil well completions of the FRS companies declined 29 percent, between 1988 and 1989, total FRS crude oil and NGL additions declined only 4 percent to 1.6 billion barrels. For the fifth year in a row, oil reserve additions were insufficient to replace production which, in 1989, equaled 1.9 billion barrels. Despite the gap between production and reserves added, the FRS companies fared better than the total industry in replacing reserves. The industry replaced 76 percent of it's crude oil and NGL production, while the FRS group replaced 84 percent (Table 43). Only in offshore areas did the FRS companies' reserve additions of oil and NGL increase (Table 44). However, while the increase was substantial (33 percent), it was not sufficient to offset the decline in onshore oil and NGL reserve additions.

Table 42. Composition of Oil and Gas Reserve Changes for FRS Companies and Total U.S. Industry, 1981-1989
(Million Barrels, COE)

Composition[a]	1981	1982	1983	1984	1985	1986	1987	1988	1989
FRS Companies									
Additions[b]	2,814	2,533	2,867	3,470	2,694	1,649	3,145	3,140	2,684
Net Purchases[c]	34	-52	559	471	434	530	656	220	112
Production	3,694	3,551	3,370	3,503	3,427	3,361	3,354	3,460	3,243
Reserve Change (Excluding Net Purchases)	-880	-1,018	-503	-33	-733	-1,713	-209	-320	-559
Reserve Change	-845	-1,069	56	438	-298	-1,183	447	-100	-447
Total U.S. Industry									
Additions[d]	7,447	5,316	6,887	6,831	6,193	4,866	6,059	7,156	5,385
Production	7,006	6,770	6,555	6,873	6,650	6,490	6,488	6,532	6,340
Reserve Change	440	-1,454	332	-43	-458	-1,623	-430	624	-955

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[a] COE = crude oil equivalent. Dry natural gas was converted at 0.177 barrels of crude oil per 1,000 cubic feet for 1981 through 1982 and 0.178 barrels for 1983 through 1989.

[b] Excludes BP America's and Exxon's total 1987 downward revisions of ANS natural gas reserves of 13.461 trillion cubic feet and ARCO's 1985 downward revision of ANS natural gas reserves of 8.3 trillion cubic feet.

[c] Purchase of minerals-in-place less sales of minerals-in-place.

[d] Excludes 1988 downward revisions of total U.S. industry's ANS natural gas reserves of 24.6 trillion cubic feet.

Note: Sum of components may not equal total due to independent rounding.

Sources: FRS companies: Energy Information Administration, Form EIA-28. Total U.S. Industry: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* DOE/EIA-0216(89) (Washington, DC, October 1990).

Table 43. Comparison of FRS and Total U.S. Reserves and Production, 1989

Reserves, Production, and Reserve Additions	FRS		Total U.S. Industry	
	1989	Percent Change From 1988	1989	Percent Change From 1988
Crude Oil and NGL End-of-Year Reserves (billion barrels)	20.3	-1.6	34.3	-2.3
Dry Natural Gas End-of-Year Reserves (trillion cubic feet)	82.7	-0.7	167.1	-0.5
Crude Oil and NGL Production (billion barrels)	1.9	-9.1	3.3	-7.0
Dry Natural Gas Production (trillion cubic feet)	7.5	-1.9	17.0	1.9
Crude Oil, NGL, and Dry Natural Gas Reserve Additions[a]				
Crude Oil and NGL (billion barrels)	1.6	-4.5	2.5	-21.7
Dry Natural Gas[b] (trillion cubic feet)	6.3	-25.4	16.1	-27.2
Total (billion barrels, COE[c])	2.7	-14.5	5.4	-24.7

[a] Reserve additions include revisions and exclude purchases and sales.

[b] Excludes downward revisions of Alaskan North Slope natural gas reserves.

[c] COE = crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per 1,000 cubic feet.

Note: Percent change was calculated from unrounded data.

Sources: FRS companies: Energy Information Administration, Form EIA-28. Total U.S. Industry: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(89) (Washington, DC, October 1990).

Table 44. Composition of U.S. Reserve Additions for FRS Companies, 1988 and 1989

Composition	Crude Oil and NGL		Natural Gas		Total	
	1988	1989	1988	1989	1988	1989
	(million barrels)		(billion cubic feet)		(million barrels, COE[a])	
Source						
Revisions	625	575	3,325	1,802	1,217	896
Improved Recovery	655	455	106	43	674	463
Extensions and Discoveries	356	533	5,013	4,453	1,248	1,326
Total	1,636	1,563	8,445	6,298	3,140	2,684
Locale						
Onshore	1,335	1,162	5,592	3,932	2,330	1,862
Offshore	302	402	2,852	2,366	809	823
Net Purchases from Non-FRS Companies	199	8	120	587	220	112

[a] COE = crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per 1,000 cubic feet.

Note: Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, Form EIA-28.

Gas Reserve Additions Remain High

The record level of gas reserves additions in 1988 was not matched in 1989, but nevertheless remained at relatively high levels. However, given that gas exploratory completions rose in 1989, finding rates would seem to have fallen, suggesting that companies are going after more marginal natural gas prospects. Overall natural gas reserve additions of the FRS companies fell 25 percent, to 6.3 trillion cubic feet (tcf) (Table 43). This is good by historic standards, but additions were still not sufficient to replace 1989's production of 7.5 tcf. The FRS group had a slightly lower natural gas reserves replacement rate than the total U.S. oil and gas industry, 83 percent compared with 95 percent. All sources of natural gas reserve additions were down, although onshore additions evidenced a greater decline than offshore (Table 44).

Exploration and Development Strategies

Finding Rates Continue to Improve

There tends to be an inverse relationship between oil prices and finding rates. Lower oil prices reduce the profitability of smaller pool prospects, inducing firms not to drill them. The result is an increased emphasis on prospects with larger field sizes. The FRS companies' total finding rate (reserve additions per well completed) for the three-year period 1987 through 1989 rose 23 percent from the previous three-year period, and was nearly 75 percent greater than the 1981 through 1983 finding rate (Table 45).

Inspection of Table 45 reveals that the offshore finding rate showed no clear trend from 1981 through 1987. In the 1986 through 1988 period, the rate increased 33 percent. The most recent finding rate of 1,499 thousand barrels per well completed (including dry holes) represents an additional 26-percent increase. While U.S. finding rates exceed Canadian finding rates, they are dwarfed by the finding rates in other foreign countries (Chapter 6, Table 53). However, U.S. offshore finding rates are more in line with foreign finding rates. Consequently, with a continuation of low oil prices, the FRS companies would be likely to shift their efforts more to the U.S. offshore in their search for larger fields. Working against this tendency has been the ever-growing restrictions on offshore exploration.

Table 45. Reserves Added per Well Completed for FRS Companies, 3-Year Weighted Average, 1981-1989
(Thousand Barrels, COE)

Reserves Added per Well[a] [b]	1981-1983	1982-1984	1983-1985	1984-1986	1985-1987	1986-1988	1987-1989
Exploration and Development Wells							
All FRS	283	302	293	269	309	399	491
Onshore	213	234	233	211	256	331	404
Offshore	996	1,007	942	902	894	1,187	1,499

[a] COE = crude oil equivalent. Dry natural gas was converted at 0.177 barrels of crude oil per 1,000 cubic feet for 1981 through 1982 and 0.178 barrels for 1983 through 1989.

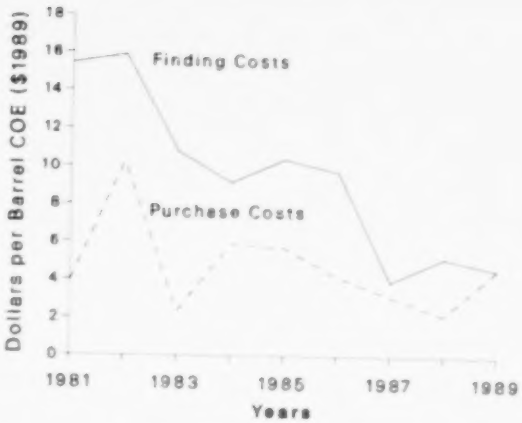
[b] Reserves added include revisions, improved recovery, and extensions and discoveries.

Source: Energy Information Administration, Form EIA-28.

Reserve Purchases Decline in Importance

During most of the 1980's, the average finding cost per barrel of reserves exceeded the average purchase price of a barrel of reserves (Figure 23). As a result, purchasing reserves was an attractive strategy, accounting for 65 percent of reserve additions for FRS companies with above average finding costs.[77] More recently, purchasing reserves has become less attractive because the difference between finding and purchase costs has narrowed over the past few years and was completely eliminated in 1989. The elimination of this cost differential was reflected in the percentage of reserve additions added through purchases. As Figure 24 reveals, between 1988 and 1989, the FRS companies' purchases of oil reserves as a share of reserve additions fell to 12 percent from 28 percent while purchases of gas reserves fell to 18 percent from 33 percent. These declines are explained by the fact that reserve purchases in 1988 were unusually high due to the sale of Tenneco's reserves on its exit from the industry. Apart from this one-time opportunity to purchase reserves in 1988, reserve purchases as a percent of total reserve additions remained largely unchanged between 1988 and 1989. Nevertheless, over the past few years there has been less reliance on reserve purchases (apart from the Tenneco transactions) due to the changing economics of the find or buy decision.

Figure 23. Annual U.S. Finding Costs and Reserve Purchase Costs for FRS Companies, 1981-1989



Note: Finding costs measured as exploration and development expenditures excluding expenditures for proved acreage divided by reserve additions less net purchases of minerals in place. Reserve additions exclude downward revisions of Alaskan natural gas reserves of 8.3 trillion cubic feet in 1985 and 13.461 trillion cubic feet in 1987. Reserve purchases are measured by expenditures for proved acreage acquisition divided by purchases of minerals in place. Dry natural gas was converted at 0.177 barrels of crude oil per 1,000 cubic feet for 1981 through 1982 and 0.178 barrels for 1983 through 1989. All values converted to 1989 dollars using the GNP implicit price deflator.

Source: Energy Information Administration, Form EIA-28.

Finding Costs

Finding Costs Remain Historically Low

The decline in oil prices in the 1980's compelled substantial changes among oil and gas producers, drillers, and oilfield service companies. Many companies exited the U.S. oil and gas industry while others were driven into bankruptcy. Sharply reduced levels of drilling activity drove drilling costs down and reduced the average value of bids for acreage. Over the same period, as was discussed in a previous section, finding rates have improved in response to lower oil prices. The combination of reduced oilfield costs and higher finding rates has led to a downward trend in the average cost of adding oil and gas reserves.

Table 46 presents finding costs as a series of 3-year weighted averages in constant 1989 dollars. This smooths out the volatility caused by the revisions of previously recorded reserves. It also partially corrects for the lag between exploration and development expenditures and their associated reserve additions. For the 1987 through 1989 period, the FRS companies' U.S. finding costs averaged $4.59 per barrel, more than one dollar less than finding costs in the 1986 through 1988 period, and almost three dollars less than finding costs in the 1985 through 1987 period. This downward trend in finding costs is observed both onshore and offshore. The combination of higher finding rates and lower unit drilling costs account for this trend over the 1980's.

Table 46 also reports exploration expenditures (including expenditures on unproved acreage) per barrel of reserves added through extensions and discoveries. This measure is intended to better reflect the cost of adding reserves from discoveries than is the measure based on total reserve additions which includes revisions of previous reserve estimates and improved recovery from producing fields. Consistent with the above measure of finding costs, costs are higher off-

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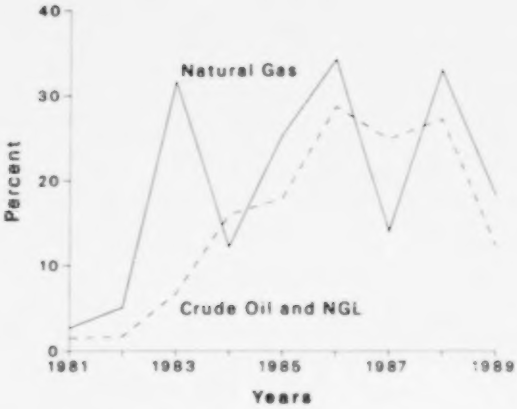
[77] Energy Information Administration, *Performance Profiles of Major Energy Producers 1987*, DOE/EIA-0206(87), (Washington, D.C., January 1989), p. 62.

Figure 24. Purchase of U.S. Reserves as a Percentage of U.S. Reserve Additions (Including Purchases) for FRS Companies, 1981-1989



Note: Reserve additions include purchases, revisions, improved recovery, and extensions and discoveries. Reserves added through intra-FRS mergers in 1982 and 1984 are excluded. 1988 excludes transfer of reserves from Sun Company to Oryx Corporation.
Source: Energy Information Administration, Form EIA-28.

shore than onshore. This is because the higher finding rate offshore (which tends to reduce the offshore finding cost) does not completely offset the higher offshore exploration expenditures per well. This measure of finding costs suggests that the differential between onshore and offshore finding costs has been generally narrowing. For instance, offshore finding costs were 48 percent higher in the 1982 through 1984 period. In the current period, 1987 through 1989, offshore finding costs are 30 percent higher than onshore. This narrowing differential can be attributed to the increase in the offshore finding rate. This trend, coupled with lower lifting costs offshore, may indicate a change in the economics of onshore versus offshore production, which could favor offshore activity.

The United States is generally believed to be a high-cost area for the production of oil and gas. This does not mean above average finding costs *per se*, but rather that there are fewer prospects that can be produced at competitive prices. Table 46 provides a comparison of U.S. finding costs with finding costs elsewhere. Despite the decline since 1980 through 1982 in U.S. finding costs, U.S. finding costs remain generally higher than finding costs outside of North America. However, the cost differential appears to have narrowed somewhat in recent years as a result of the decline in U.S. exploration and development activity.

The U.S. finding costs of the non-FRS firms are also presented in Table 46. The table shows that non-FRS average finding costs were consistently higher than average finding costs for FRS companies.

After-Tax Finding Costs

The second section of Table 46 reports after-tax finding costs with adjustments made for lags between expenditures and reserve additions.[78] After-tax finding costs have declined since 1982, but not as much as pretax finding costs. Specifically, between 1982 and 1989, pretax finding costs fell 60 percent (from $11.59 to $4.59 per barrel of reserves) while after-tax finding costs declined 49 percent from $7.17 to $3.64 per barrel. At least three factors have contributed to this difference. First, during the 1980's the composition of expenditures shifted from exploration to development. Exploration expenditures tend to receive more favorable tax treatment than do development expenditures. Second, major petroleum companies have been required by Federal law to amortize, rather than immediately expense, a growing portion of their intangible drilling costs. Third, the 1986 Tax Reform Act (TRA) contained a number of provisions which increased after-tax finding costs.

Lifting Costs

Lifting costs are the costs of extracting oil and gas from the ground. One of the challenges facing oil and gas producers in the 1980's was to reduce lifting costs in the face of declining oil prices in order to improve the profitability of oil and gas operations. Reductions in lifting costs have been achieved through organizational cost cutting, spreading fixed costs over more units of production, reducing production from higher cost operations, and installation of new technology. Also, one of the components of lifting costs is production taxes, most of which are levied as a percentage of wellhead revenues. Consequently, as oil prices declined in the 1980's so did production taxes.

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[78] Finding costs are adjusted for taxes by subtracting the present value (assuming a 10-percent discount rate) of the reduction in future taxes attributable to each expenditure category. The lag assumptions are based on A.T. Guernsey, *Economics of Domestic Crude Oil and Natural Gas Exploration and Development 1959-1976* (Shell Oil Company, Houston 1977) and Glenn A. Welsh and Edward B. Deakin, *Measuring and Reporting the Replacement Cost of Oil and Gas Reserves* (American Petroleum Institute, Washington, D.C., 1977) Details of the tax treatment for the categories of expenditures can be found in Energy Information Administration, *Performance Profiles of Major Energy Producers 1987*, DOE/EIA-0206(87) (Washington, D.C., January 1989), p. 65.

Table 46. Costs of Adding Reserves for FRS Companies and Non-FRS Companies, 3-Year Weighted Average, 1982-1989

(1989 Dollars per Barrel, COE)

Cost Measure	1982-1984	1983-1985	1984-1986	1985-1987	1986-1988	1987-1989
FRS Companies						
Exploration and Development Expenditures per Barrel of Reserve Additions[a] [b]	11.59	10.04	9.72	7.55	5.63	4.59
Onshore	10.00	8.46	8.72	6.66	4.91	3.88
Offshore	15.41	14.26	12.25	10.38	7.97	6.83
FRS Companies						
Exploration Expenditures per Barrel of Reserves Added through Extensions and Discoveries	10.44	9.45	8.20	7.56	6.16	4.98
Onshore	8.68	7.66	7.21	7.19	5.71	4.44
Offshore	12.84	12.08	9.75	8.13	6.91	5.80
Canada	5.92	4.00	4.35	3.26	5.35	6.40
Other Foreign	6.77	6.07	5.93	5.10	4.75	4.06
After-Tax Finding Cost per Barrel of Reserve Additions[a] [c]	7.17	6.63	7.01	6.24	4.85	3.64
Onshore	5.98	5.24	5.63	4.83	3.90	3.09
Offshore	10.06	10.36	10.51	10.70	7.68	5.36
Cost per Barrel of Purchased Reserves[a] [d]	6.14	5.45	5.65	4.26	2.78	2.72
Non-FRS Oil and Gas Producers[e]						
Exploration and Development Expenditures per Barrel of Reserve Additions[a] [b]	12.99	10.83	11.17	9.24	6.77	5.93

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[a] COE = crude oil equivalent. Dry natural gas was converted at 0.177 barrels of crude oil per 1,000 cubic feet for 1982 and 0.178 barrels for 1983 through 1989.

[b] Exploration and development expenditures, excluding purchases of minerals-in-place divided by oil and gas reserve additions.

[c] As in (a), but adjusts for lag and tax effects.

[d] Expenditures for proved acreage acquisition divided by purchases of minerals in place.

[e] Includes only companies that reported data for all three years of the intervals shown.

Note: All values were converted to 1989 dollars using the GNP implicit price deflator.

Sources: FRS Companies: Energy Information Administration, Form EIA-28. Non-FRS Companies: Arthur Andersen & Co., *Oil and Gas Reserve Disclosures*, 1985, 1986, 1987, 1988 and 1989 editions (Chicago, Il, 1986, 1987, 1988, 1989 and 1990).

Table 47. Oil and Gas Lifting Costs for FRS Companies, 1981-1989

(1989 Dollars per Barrel, COE)

Lifting Costs[a] [b]	1981	1982	1983	1984	1985	1986	1987	1988	1989
Costs With Production Taxes									
Onshore	12.76	11.00	9.52	8.95	8.03	5.83	5.52	5.13	5.39
Offshore	8.91	7.09	7.01	6.11	7.32	3.56	3.15	3.80	3.93
Total	11.86	10.04	8.92	8.23	7.87	5.27	4.95	4.81	5.05
Costs Without Production Taxes									
Total	4.14	4.84	5.13	5.09	5.55	4.64	4.34	4.27	4.35

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[a] Calculated by dividing total lifting costs by total production of crude oil, natural gas liquids, and natural gas, on a crude oil equivalent basis.

[b] COE = crude oil equivalent. Dry natural gas was converted at 0.177 barrels of crude oil per 1,000 cubic feet for 1981 through 1982 and 0.178 barrels for 1983 through 1989.

Note: All values converted to 1989 dollars using the GNP implicit price deflator.

Source: Energy Information Administration, Form EIA-28.

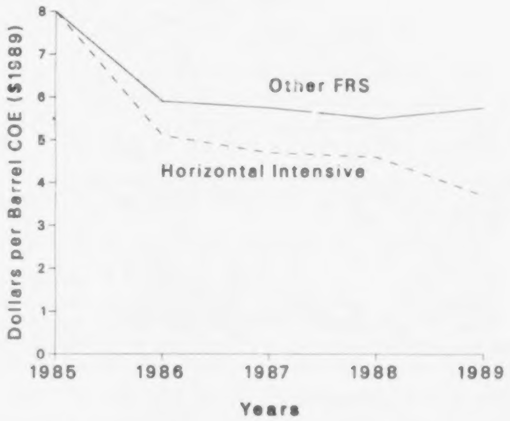
Between 1982 and 1989, the FRS companies' U.S. lifting costs (in 1989 dollars) fell 50 percent, from $10.04 per barrel (oil and gas on a crude-oil equivalent basis) to $5.05 per barrel (Table 47). Most of this decline was the result of reduced production taxes, which fell from $7.72 per barrel in 1981 to $0.54 per barrel in 1988 (in 1989 dollars). Due to higher oil prices in 1989, production taxes rose to $0.70 per barrel. State production taxes, which mainly are levied as a percentage of oil and gas revenues, were at a peak value of $1.60 per barrel in 1981 (1989 dollars) but declined thereafter, and amounted to $0.71 per barrel in 1989. The Federal Windfall Profit Tax (WPT) was levied as a percentage of the difference between the selling price of crude oil less an inflation-adjusted base price and State production taxes. The percentage varied by category of production. The WPT was at a peak value of $6.12 per barrel (1989 dollars) of FRS oil and gas production in 1981. WPT payments declined after 1981 as oil prices declined and the inflation-adjusted base price rose. By 1986, the selling price of oil had fallen below the WPT base price. In August 1988, the WPT was repealed. In 1989, refunds of previous overpayments of the WPT amounted to a penny per barrel for the FRS companies.

Direct (pretax) lifting costs fell by over a dollar per barrel in recent years compared with the years prior to the oil price crash of early 1986. Much of the reduction in direct lifting costs was due to the shut-in of more marginal wells, and the cutting of general overhead. The shift towards natural gas, which tends to have lower lifting costs than oil, also accounts for some of the decline. The increasing share of oil production from Alaska has also led to a reduction in direct lifting costs since Alaskan lifting costs are lower than the national average. Finally, the cessation of production from high-cost stripper wells has also tended to reduce direct lifting costs.

Despite the downward trend in lifting costs, both with and without production taxes, lifting costs were actually higher in 1989 than in 1988. Offshore lifting costs were up 3 percent in 1989 dollars to $3.93 per barrel while onshore lifting costs increased by 5 percent to $5.39 per barrel. Overall, lifting costs increased 5 percent to $5.05 per barrel. Direct lifting costs rose 2 percent to $4.35 per barrel. There are two reasons for this slight increase in lifting costs. First, the natural decline in production due to depletion of the resource base has increased the average cost of extracting a barrel of oil.[79] Second, the increase in the price of oil in 1989 led to increased production from marginal wells, increasing average lifting costs.

The FRS companies, as mentioned earlier, have sought to lower production costs through technological advances. Three FRS companies (Oryx, Burlington Resources, and Union Pacific) have been particularly active in the use of horizontal drilling to boost production and lower costs. Figure 25 depicts the lifting costs of this group of firms as well as the lifting costs of the other FRS firms. The lifting costs of firms active in horizontal drilling declined in 1989 while lifting costs for the other FRS companies rose. Although not conclusively proved, it does suggest that there is a correlation between the use of horizontal drilling and lower lifting costs.

Figure 25. Onshore Lifting Costs for Horizontal Intensive FRS Companies and Other FRS Companies, 1985-1989



Note: All values converted to 1989 dollars using the GNP implicit prices deflator.
Source: Energy Information Administration, Form EIA-28.

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[79] For instance, the lifting costs of Alaskan crude have increased from $3.28 in 1988 to $4.75 in 1989 due to a decline in production from the North Slope. Source: BP America's *Operations Report* 1989, pp. 30-31.

6. Foreign Petroleum Developments

The United States has largely relinquished the central role it played in world petroleum developments in the first half of this century. U.S. oil production now accounts for less than 20 percent of world oil output. World oil prices, for better or worse, are set abroad.

The FRS companies are both producers and refiners of oil. However, as a group, they refine more oil than they produce. Hence they are large net purchasers of oil produced abroad, typically by the state-owned national oil companies of members of the Organization of Petroleum Exporting Countries (OPEC). The profitability of the FRS companies' foreign operations thus hinges both on the level of world oil prices and the spread between crude oil prices and refined products' prices.

World oil prices rose considerably in 1989. The average refiner's acquisition cost of crude oil in the United States in 1989 was $17.97 per barrel, up more than 22 percent over the 1988 average of $14.67 per barrel. Higher oil prices were good for oil producers, but they were not necessarily good for oil refiners. As measured by *Petroleum Intelligence Weekly*, spot refining margins for most major crudes in most major markets were strong from April 1989 to the end of the year.[80]

Financial Performance of the FRS Companies

The foreign petroleum operations of the FRS companies tend to be dominated by the largest firms. The top four group of FRS companies (Exxon, Chevron, Mobil, and Texaco) accounted for 76 percent of foreign petroleum net income (See Table 48). The ten smallest FRS companies accounted for only 4 percent of total FRS foreign petroleum net income. The patterns of asset deployment and investment are similar.

The top four group is also highly dependent on foreign petroleum activities for total net income. In 1989, foreign petroleum activities accounted for 41 percent of total FRS net income. However, foreign petroleum activities accounted for 75 percent of the net income of the top four group.

Profitability in 1989

With world oil prices up more than 20 percent, higher FRS foreign production profitability would be expected. However, FRS foreign production profits were not nearly as buoyant as the world oil market. FRS operating revenues from foreign production rose only 11 percent, to $30.0 billion. This outcome was due, in part, to a 4-percent decline in FRS foreign net equity oil production. High taxes and lower gains on asset disposals combined to produce just a 9-percent gain in FRS foreign production net income, up from $4.3 billion in 1988 to $4.7 billion in 1989.[81]

Since refined products prices did not rise as much as crude oil prices, FRS refining/marking sector revenues rose less than 7 percent, to $143 billion in 1989. Operating costs (primarily purchases of crude oil) rose 8 percent, to $141 billion, so operating leverage worked against the FRS refining/marketing sector. Foreign refining/marketing sector net income declined 25 percent, from $2.4 billion in 1988 to $1.8 billion in 1989. In the 1980's, FRS foreign refining/marketing net income has fluctuated between $4.3 billion in 1980 and $0.5 billion in 1985. While the earnings decline was surely disappointing to corporate managements, 1989 FRS foreign refining/marketing earnings were considerably above the 1981-1989 average of $1.5 billion.

Aided by a stronger tanker market, the net income of international marine operations rose 85 percent, to $0.2 billion in 1989, on revenues of $2.2 billion. Overall, the after-tax operating income of all FRS foreign petroleum operations declined almost 3 percent, to $6.7 billion, in 1989. Since the FRS companies are large net purchasers of crude oil, refining margins have become more important to overall profitability than the level of crude oil prices. In years such as 1989, when crude oil prices are higher while refining margins decline, overall net income is likely to decline.

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[80] *Petroleum Market Intelligence*, January 10, 1990, p. 8.

[81] The marginal tax rate is defined here as the change in FRS income taxes paid with respect to foreign production income divided by the change in FRS foreign pre-tax income. Taxes are discussed in more detail in a subsequent section.

Table 48. Foreign Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1986-1989

(Billion Dollars)

Line of Business	1986	1987	1988	1989	Percent Change 1988-1989
Foreign Petroleum					
Top Four	7.1	5.0	5.7	5.1	-11.3
Five Through Twelve	0.6	1.0	1.0	1.4	43.3
All Other	0.05	0.4	0.2	0.2	23.4
All FRS	7.7	6.4	6.9	6.7	-2.6
Foreign Petroleum Segments					
Production					
Top Four	4.3	4.4	3.4	3.5	3.2
Five Through Twelve	0.4	0.7	0.7	1.0	33.8
All Other	0.02	0.4	0.2	0.2	12.8
All FRS	4.7	5.4	4.3	4.7	8.7
Refining/Marketing					
Top Four	2.7	0.7	2.2	1.5	-33.3
Five Through Twelve	0.2	0.3	0.2	0.3	40.7
All Other	0.02	0.04	0.01	0.04	400.0
All FRS	2.9	1.0	2.4	1.8	-25.2
International Marine					
Top Four	0.1	-0.1	0.1	0.1	22.9
All Other[a]	0.004	0.02	0.04	0.1	346.2
All FRS	0.1	-0.1	0.1	0.2	84.7

[a] Company groups are combined to prevent disclosure.

Note: Sum of components may not equal total due to independent rounding. Percent changes are based on unrounded data.

Source: Energy Information Administration, Form EIA-28.

Return on Assets

For the FRS companies, foreign production activities have tended to be much more profitable than foreign refining. Figure 26 illustrates that rates of return (defined as a sectoral contribution to net income divided by net investment in place) for foreign refining/marketing has been variable: prior to 1988, foreign refining rates of return were higher than domestic rates of return, but domestic refining/marketing has been the superior performer over the past 2 years (Figure 27). Foreign production has also been consistently more profitable than domestic production, as shown in Figure 28.

Investments and Cash Flow

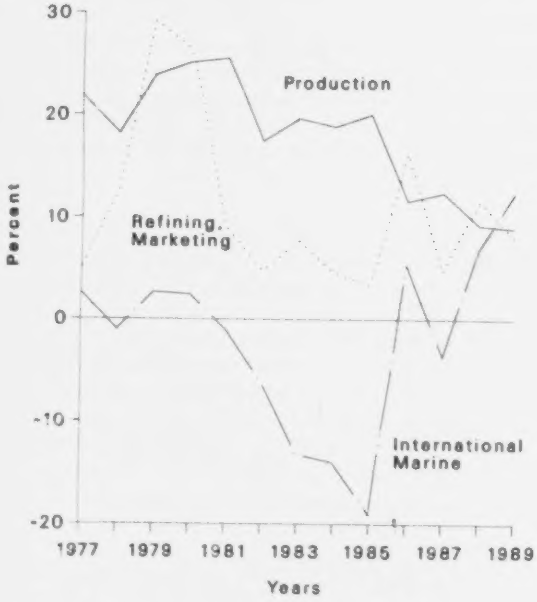
The FRS companies increased total foreign petroleum investment by 16 percent in 1989, to $16 billion. This occurred in an environment where FRS investments in domestic petroleum declined significantly. FRS investment in foreign production activities exceeded FRS domestic production investment in 1989 for the first time.

Investment in foreign exploration and production rose 21 percent, to $12.4 billion (Table 49), while investment in foreign refining and marketing increased just under 1 percent, to $3.4 billion. Investment in both segments has increased in every year since 1980 (Figure 29).

Another striking feature of the FRS companies' 1989 investment program was the declining importance of acquisitions: expenditures for the acquisition of foreign proved acreage declined 8 percent in 1989, to $3.2 billion. Most of this amount went for a single transaction: Exxon's acquisition of Texaco Canada. By implication, FRS companies were spending more of their foreign investment dollar on finding oil in the ground, rather than buying up already-discovered reserves.

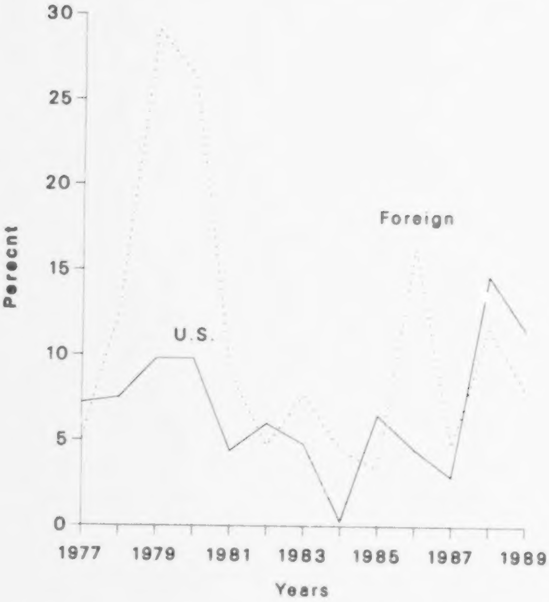
Rising levels of investment have also transformed foreign oil operations from a net source of cash flow to a net "use" of cash flow. FRS foreign operations yielded $14.6 billion (profits plus dry hole expense plus depreciation, depletion, and amortization) in 1989, up fractionally from 1988, while investments, as noted above rose from $13.7 billion in 1988 to $16 billion in 1989. Foreign refining/marketing is a minor net use of cash ($0.4 billion), while foreign exploration and production has become a large net user of cash ($1.5 billion).

Figure 26. Profit Rates in Foreign Petroleum Segments for FRS Companies, 1977-1989



Note: Rate of return is net income divided by net investment in place.
Source: Energy Information Administration, Form EIA - 28.

Figure 27. Rate of Return in U.S. and Foreign Refining/Marketing for FRS Companies, 1977-1989



Note: Rate of return is net income divided by net investment in place.
Source: Energy Information Administration, Form EIA - 28.

Production Trends and Lifting Costs

The foreign oil production of the FRS companies is a poor sample, both in costs and in geographic distribution, of foreign oil production at large. Most FRS companies' oil operations in the Middle East, Africa, and Asia were nationalized in the 1970's. Their remaining foreign production is heavily concentrated in Canada and Western Europe. FRS production outside the industrialized nations of the Organization for Economic Cooperation and Development (OECD) is a relatively small fraction of non-OECD production, since most foreign reserves and production are controlled by foreign governments, rather than owned by private companies.

Production Trends

Figure 30 shows the distribution of FRS oil and gas production by region since 1977. FRS production accounts for 58 percent of total oil production in the United States, 29 percent of total oil production in Canada, 27 percent of total oil production in Europe, but only 2 percent of Middle East production and 5 percent of Other Western Hemisphere production (Table 50).[82]

Figure 31 compares FRS and regional ratios of oil reserves to oil production. This ratio is an indicator both of the intensity with which current known reserves are being exploited, and also of the potential to increase production from known reserves. The ratio of FRS reserves to FRS production closely tracks the overall regional ratios in North America and Western Europe. Outside of OECD, total reserves are far greater than total production. The excess reserves of countries such

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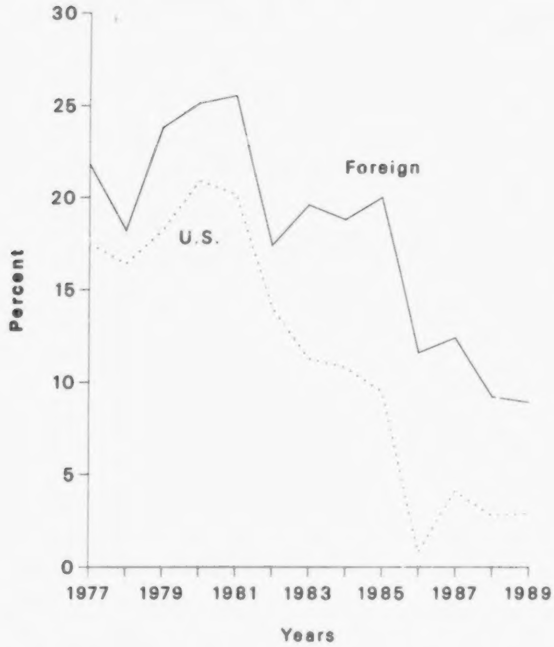
[82] See "Foreign Operations" in the glossary for definitions of the geographical regions used to disaggregate FRS foreign operations.

Figure 28. Rate of Return in U.S. and Foreign Production for FRS Companies, 1977-1989



Note: Rate of return is net income divided by net investment in place.
Source: Energy Information Administration, Form EIA - 28.

as Saudi Arabia, Iraq, Venezuela, and Mexico are in the hands of national oil companies, not the FRS companies. The FRS regional reserves/production ratios are roughly equal, at about 10 years in all regions. The FRS companies apparently exploit their reserves at roughly the same level of intensity wherever they are found, and do not own large volumes of unexploited reserves.

Total FRS foreign oil production declined more than 4 percent in 1989, to 3.47 million barrels per day. FRS foreign natural gas production, however, increased 9.7 percent, to 9.2 billion cubic feet per day.

Canada continues to be a major center of FRS petroleum production activity. FRS Canadian oil production rose slightly, to 583,000 barrels per day in 1989. The largest FRS Canadian producer is Exxon's Imperial Oil unit. Exxon's net ownership share of Imperial's Canadian production is 269,000 barrels per day, accounting for almost half of FRS Canadian oil production.[83] Exxon Canadian production rose 65,000 barrels per day in 1989, primarily due to Imperial's acquisition of oil production formerly owned by Texaco Canada. Amoco also increased Canadian oil production by 41 percent, to 112,000 barrels per day, primarily due to the 1988 acquisition of the assets of Dome Petroleum. The third-largest FRS Canadian oil producer is Chevron, which produced some 70,000 barrels per day, down slightly from 1988.

FRS Canadian natural gas production increased 30 percent in 1989, following a 35-percent increase in 1988, to an average 2.3 billion cubic feet per day. Since Canadian gas production rose only 6 percent in 1989, to 9.3 billion cubic feet per day, this reflects a major increase in FRS market share.[84] As in oil, Amoco increased output 51 percent, to 0.8 billion cubic feet per day, also due to the Dome merger. Other major FRS Canadian gas producers are Mobil (0.45 billion cubic feet per day), Exxon (0.39 billion cubic feet per day) and Chevron (0.29 billion cubic feet per day).

The ratio of FRS Canadian gas reserves to production declined throughout the 1980's, to about 17 years in 1989, but remained double the FRS companies' U.S. gas reserves/production ratio. This suggests that FRS Canadian gas production can continue to expand as new markets for Canadian gas become available. On the other hand, expansion of Canadian gas output may not be particularly profitable for the FRS companies. Amoco, the largest FRS Canadian gas producer and one of the larger Canadian oil producers, reported a loss on its Canadian production operations of $147 million in 1989. Imperial Oil also reported an earnings decline in 1989.

FRS European oil production declined nearly 12 percent in 1989, to 1.1 million barrels per day. European (and FRS) production is dominated by output from the North Sea, primarily from the United Kingdom (U.K.) and Norway, with minor volumes of petroleum coming from the Netherlands, Denmark, and Germany. The North Sea is one of the commonest locations for FRS companies seeking foreign production. Fourteen FRS companies recorded some European oil production during 1989, and there were few major changes in output for most of the members of this group. Exxon accounted for virtually all of the decline, with its European net equity production falling from 429,000 barrels per day in 1988 to 338,000 barrels per day in 1989. Exxon has substantial interests in the accident-prone U.K. North Sea. While no misfortunes befell any

[83] All of the references to oil and gas production by specific companies in this section are taken from corporate annual reports or other publications, not from Form EIA-28. These sources include: Amoco Corp., *Annual Report 1989*, Chevron Corporation, *Supplement to the 1989 Annual Report*, Exxon Corp., *1989 Financial and Statistical Supplement to the Annual Report*, Mobil Corp., *Financial and Operating Statistics 1989*, Occidental Petroleum Corp., *1989 Annual Report* and *1989 Annual Report on Form 10-K*, Phillips Petroleum Company, *Annual Report 1989*, Texaco, Inc., *Annual Report 1989*, and USX, *1989 Annual Report*.

[84] Petroleum Monitoring Agency Canada, *Canadian Petroleum Industry 1989 Monitoring Report*, p. 47.

Table 49. Additions to Investment in Place in Foreign Petroleum for FRS Companies Ranked by Total Energy Assets, 1986-1989
(Billion Dollars)

Line of Business	1986	1987	1988	1989	Percent Change 1988-1989
Foreign Petroleum					
Top Four	4.9	6.1	5.4	11.6	114.0
Five Through Twelve	2.1	2.9	7.3	3.0	-59.2
All Other	0.7	0.8	1.0	1.4	34.7
All FRS	7.7	9.9	13.7	16.0	16.2
Foreign Petroleum Segments					
Production					
Top Four	2.9	3.9	3.1	8.0	159.4
Five Through Twelve	2.0	2.8	6.2	3.0	-50.8
All Other	0.7	0.6	1.0	1.3	35.7
All FRS	5.5	7.4	10.3	12.4	20.8
Refining/Marketing					
Top Four	2.0	2.2	2.2	3.5	54.2
All Other[a]	0.1	0.2	1.1	-0.2	NM
All FRS	2.1	2.4	3.3	3.4	0.9
International Marine					
All FRS[a]	0.04	0.1	0.2	0.2	43.7

[a] Company groups are combined to prevent disclosure.

NM = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Exxon-operated platform, Exxon did own interests in fields whose production was affected by accidents on platforms operated by others. Other major FRS oil producers in Europe include Mobil, with net ownership production of 155,000 barrels per day, Dupont's Conoco unit, Chevron (80,000 barrels per day), and Texaco (75,000 barrels per day).

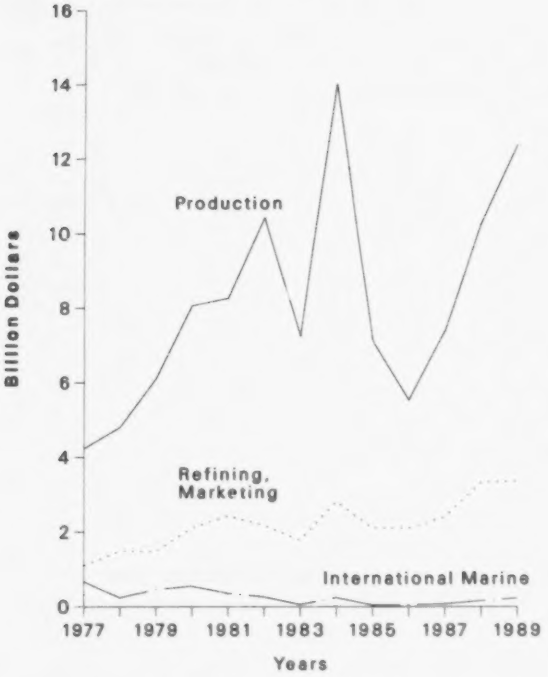
FRS European natural gas production increased just over 1 percent in 1989, to 3.65 billion cubic feet per day, even as oil production declined. Exxon accounts for almost a third of FRS European production, with 1989 output greater than 1 billion cubic feet per day. Other major FRS European gas producers include Mobil (0.7 billion cubic feet per day), Dupont's Conoco unit, Phillips, USX's Marathon Oil subsidiary, and Amoco (each producing approximately 0.3 billion cubic feet per day of gas).

The Other Eastern Hemisphere region was a major growth area for both FRS investment and production in 1989, and now stands second only to Europe for FRS petroleum production. The region includes several countries where FRS companies are active, including Indonesia, Australia, Malaysia, Thailand, and Pakistan. FRS Eastern Hemisphere oil production rose 7 percent in 1989, to 614,000 barrels per day. Exxon accounted for about half of FRS Eastern Hemisphere production, with output of 309,000 barrels per day of primarily offshore production from the Bass Straits fields in Australia and offshore Trengganu fields in Malaysia. Exxon's output declined 5 percent in 1989. Other major producers are Mobil (Indonesia), Unocal (Indonesia and Thailand), and ARCO with 50,000 barrels per day of production in Indonesia.

As in other regions, FRS Eastern Hemisphere natural gas output grew substantially in 1989. Production rose 10 percent, to 2.56 billion cubic feet per day. Gas production was dominated by Mobil, which produced 1.5 billion cubic feet per day of gas from the Arun field in Indonesia. Arun natural gas is liquefied and exported to Japan and Korea. Mobil also produced 51,000 barrels per day of condensate from Arun in 1989. Other major gas producers were Exxon (0.36 billion cubic feet per day, with production from both Australia and Malaysia), and Unocal (Thailand and Indonesia).

FRS African oil production declined fractionally from 529,000 barrels per day in 1988 to 524,000 barrels per day in 1989. The largest FRS African producer was Chevron, with 1989 net equity production of 187,000 barrels per day from Nigeria, Angola, and Zaire. Amoco, with net equity oil production of 141,000 barrels per day from Egypt, was the other major FRS

Figure 29. **Additions to Investment in Place in Foreign Petroleum for FRS Companies, 1977-1989**



Source: Energy Information Administration, Form EIA - 28.

African producer.[85] Amoco maintains interests in Gabon and the Congo as well. Mobil is also a major African producer, with net equity production of 69,000 barrels per day from Nigeria. FRS African gas production was only 0.03 billion cubic feet per day in 1989. FRS companies do not participate in any current African gas export project. Domestic gas markets are poorly developed.

The Middle East contains the world's largest oil reserves, and accounts for more than a third of world oil production. The FRS companies, however, have largely lost their equity positions in Middle East crude oil. FRS Middle East oil production in 1989 was only 310,000 barrels per day, down nearly 3 percent from 1988. Dupont's Conoco unit is the largest FRS producer in the Middle East, with output from offshore fields in the Emirate of Dubai within the United Arab Emirates. Other FRS Middle East producers include Exxon, with an interests in Yemen, and Texaco, which acquired a concession in the Kuwaiti half of the Neutral Zone when it acquired Getty Oil. FRS Middle East gas production was an insignificant 0.07 billion cubic feet per day in 1989.

FRS Western Hemisphere oil production declined more than 11 percent in 1989, to 334,000 barrels per day. Amoco is the largest FRS Latin American oil producer, with output of 64,000 barrels per day from Trinidad, and 44,000 barrels per day from Argentina. Amoco's production in both countries increased slightly, even as output from other FRS companies declined. Occidental Petroleum has the most extensive Latin American operations of any FRS company with net production of just over 100,000 barrels per day from Colombia Peru, Bolivia, and Argentina. Occidental's production declined slightly in 1989. Texaco has equity production of about 90,000 barrels per day from Ecuador, Colombia, and Trinidad. Texaco's output declined by about 10,000 barrels per day from 1988 levels.

FRS Western Hemisphere natural gas production was substantial: 0.57 billion cubic feet per day in 1989, up more than 3 percent from 1988 levels. Most of this production (0.35 billion cubic feet per day) comes from Amoco's Trinidad operation. Texaco, with production of 0.12 billion cubic feet per day, accounts for much of the rest. Exxon also produced 0.06 billion cubic feet per day of gas in Latin America.

Lifting Costs

Table 51 shows lifting costs per barrel of crude oil equivalent by region for recent years. Lifting costs are defined as actual out-of-pocket expenditures for oil production, and should include neither capital expenditure elements nor any non-cash expenses such as depletion, depreciation, or amortization.

Lifting cost figures, like most aggregate financial ratios, should be treated with care. They are regional aggregations of many disparate individual company operations. Actual production costs are largely determined by field characteristics, such as well productivity, whether the field is onshore or offshore, and whether or not secondary or enhanced recovery techniques are in use, rather than by field location. Further, natural gas lifting costs are typically lower than oil lifting costs, so the average level of lifting costs is also affected by natural gas' share of regional production.

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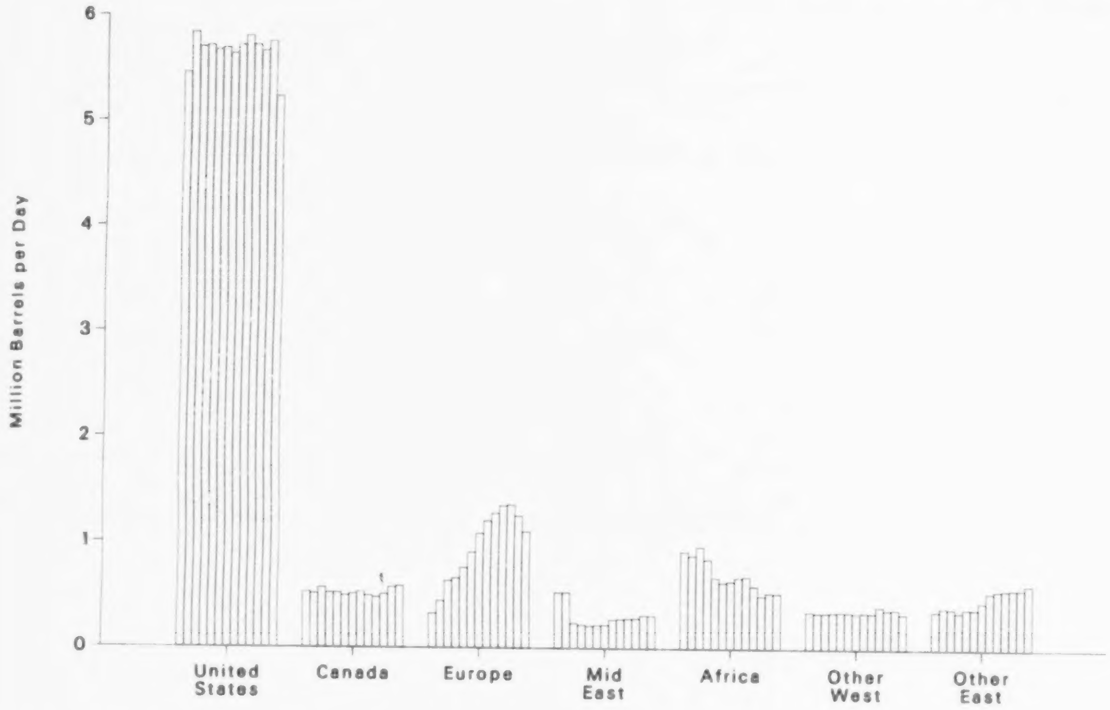
[85] Amoco, *Annual Report 1989*, p. 10.

Figure 30. FRS Companies' Oil and NGL Production By Geographical Area, 1977-1989



Note: Each bar equals one year.
Source: Energy Information Administration, Form EIA-28.

Nonetheless, regional patterns are revealing. European unit lifting costs rose sharply in 1989. The relatively high level of lifting costs in the United States and Canada can be explained by low well productivities in these mature producing areas (see Table 52). Lifting costs in Africa, the Middle East, and the Other Eastern Hemisphere regions all converged on $2.50 per barrel in 1989, while Other Western Hemisphere direct lifting costs jumped 36 percent to $3.03 per barrel in 1989.

A clear distinction can be drawn between high lifting cost regions (Canada, the United States, and Europe) and the rest of the world. This distinction is reduced (but not eliminated) by imposition of production taxes and royalties, which tend to be higher in the lower-cost regions.

Development Costs

Direct lifting costs are only one measure of oil production costs. Oil and gas production (particularly offshore production) is a very capital intensive activity. Table 52 illustrates a measure of the capital cost of oil production by region: FRS development costs per well divided by average oil production per well. This table illustrates several points:

- drilling wells in the United States and Canada is inexpensive compared to the rest of the world;
- production wells are most expensive in Europe and Africa, where much of the production comes from offshore;
- The average production well is four-to-twenty times more productive outside of North America, and this effect dominates variations in well costs.

By this measure, the capital cost of developing North Sea oil is half the cost of developing U.S. oil. The cost of developing Middle East oil is one-sixth the cost of developing oil in the United States. These cost differentials are one of the forces pushing the FRS companies to invest increasing sums abroad.

Table 50. FRS Companies' Share of World Oil and Natural Gas Production, 1989

Geographic Area	Total Production	FRS Companies	FRS Companies Percent Change 1988-1989	FRS Share of Total Production
	(million barrels per day)		(percent)	
Oil and NGL Production				
United States	9.09	5.24	-9.1	57.6
Canada	1.97	0.58	1.4	29.4
Europe	4.12	1.11	-11.9	26.9
Africa	6.13	0.52	-0.8	8.5
Middle East	16.92	0.31	-2.7	1.8
Other Eastern Hemisphere	3.68	0.62	7.1	16.8
Other Western Hemisphere	7.08	0.33	-11.3	4.7
Non-Communist World	48.98	8.71	-7.2	17.8
	(billion cubic feet per day)		(percent)	
Natural Gas Production				
United States	46.53	20.50	-1.9	44.1
Canada	9.51	2.34	30.1	24.6
Europe	18.19	3.65	1.1	20.1
Africa	5.97	0.03	-12.0	0.5
Middle East	9.12	0.08	-8.7	0.9
Other Eastern Hemisphere	11.62	2.56	9.9	22.2
Other Western Hemisphere	7.78	0.57	3.3	7.3
Non-Communist World	108.72	29.72	1.4	27.4

Note: Percent change computed from unrounded data. Foreign data exclude centrally planned economies.
Source: FRS Companies: Energy Information Administration, Form EIA-28. Regional totals: Table B33 and sources cited there.

Aggregate Drilling and Investment Levels

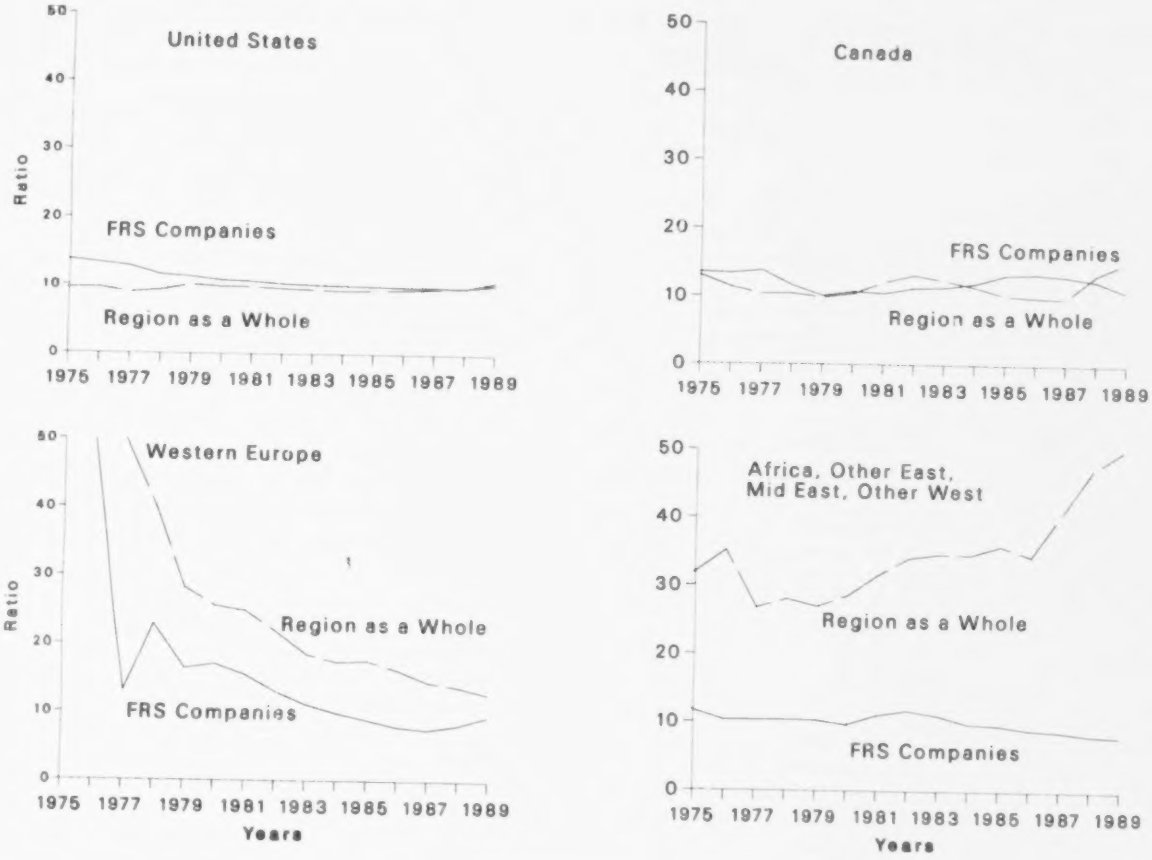
During 1989, the FRS companies drilled 4,348 development wells in the United States, a decline of 19 percent. The number of foreign development wells drilled in 1989 declined 44 percent, to only 722. The decline in development drilling was concentrated in Canada. The number of FRS Canadian development wells declined 70 percent, to only 243. Where Canadian drilling accounted for almost two-thirds of foreign development drilling in 1988 and prior years, the proportion was reduced to only one-third in 1989.

FRS development drilling in other foreign regions increased by 3 percent in 1989, to 479 wells. All of the growth was in the Other Eastern Hemisphere region, where development drilling jumped 28 percent, to 177 wells. Drilling in the Other Western Hemisphere region declined 12 percent, to 125 wells. The other regions recorded only fractional losses or gains.

Despite the decline in the number of wells drilled, FRS foreign development spending increased 30 percent in 1989, to $6.3 billion. Despite the sharp drop in Canadian drilling levels, FRS Canadian development expenditures increased by a third, to $2 billion.

In Canada, aggregate spending levels often were not closely linked to levels of drilling activity because purchases of property, plant, and equipment in the course of foreign acquisitions were booked as development expenditures. In 1988, Canadian development spending included Amoco's purchase of Dome Petroleum. In 1989, development spending included Exxon's purchase of Texaco Canada. Correcting for the effects of the two acquisitions, it is likely that FRS Canadian development expenditures for new assets declined in 1989, though not nearly as much as drilling declined.

Figure 31. FRS Companies' and Aggregate Ratio of Regional Oil and NGL Reserves to Production, 1975-1989



Sources: FRS Companies: Energy Information Administration, Form EIA-28. Regions: Table B33.

FRS foreign development expenditures outside of Canada increased 13 percent, to $4.3 billion. FRS development spending increased significantly in every region except Other Western Hemisphere, where expenditures dropped by 27 percent, to $0.3 billion. The largest gainer was the Other Eastern Hemisphere region, where expenditures rose 39 percent, to $1.1 billion.

Expenditures tended to rise more rapidly than the number of wells drilled in all regions, suggesting either higher drilling costs or a shift in the composition of drilling effort to deeper and/or more offshore wells.

Resource Development and Exploration Trends

The FRS companies' worldwide exploration spending, including unproved property acquisition, was $9.5 billion, down 15 percent from 1988. All of the decline occurred in domestic exploration spending. FRS foreign exploration spending rose more than 7 percent, to $4.5 billion. All of the growth was accounted for by a single unusual transaction.[86] Excluding this transaction, foreign exploration spending declined 3 percent. Even so, foreign exploration expenditures accounted for an increasing share of the FRS companies' worldwide exploration budget.

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[86] In 1989, a foreign-owned FRS company spent $450 million purchasing certain assets located in the Eastern Hemisphere from its parent in what was classified as an "unproved property acquisition." The assets were not, however, unproved property in the sense that it would normally be used for measuring exploration effort.

Table 51. FRS Companies' U.S. and Foreign Production Costs and Production Taxes, 1987-1989
(Dollars Per Barrel of Oil Equivalent)

Geographic Area	Direct Lifting Costs			Royalties and Taxes			Total Lifting Costs		
	1987	1988	1989	1987	1988	1989	1987	1988	1989
United States	4.03	4.10	4.35	0.57	0.52	0.71	4.60	4.62	5.06
Canada	3.60	4.05	4.19	0.42	0.35	0.31	4.02	4.40	4.50
Europe	4.07	4.54	4.80	0.80	0.65	0.50	4.87	5.20	5.30
Africa	2.67	2.94	2.48	2.43	1.03	1.16	5.10	3.97	3.64
Middle East	2.53	2.25	2.50	2.66	1.44	1.35	5.19	3.69	3.85
Other Eastern Hemisphere	2.17	2.55	2.49	2.62	1.69	1.45	4.79	4.24	3.94
Other Western Hemisphere	2.43	2.23	3.03	1.78	1.13	1.32	4.21	3.36	4.35
Total Foreign	3.25	3.54	3.66	1.47	0.93	0.86	4.71	4.48	4.51
Total FRS	3.75	3.90	4.10	0.88	0.67	0.76	4.64	4.57	4.86

Note: Sum of components may not equal total lifting costs due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table 52. FRS Companies' Unit Development Costs by Geographic Area, 1987-1989

Geographic Area	Number of Wells (1)	Oil and Gas Production (M BPD) (2)	Oil and Gas Production per Well (BPD) (3)=(2)/(1)	Development Expenditures ($ MM) (4)	Number of Development Wells Drilled (5)	Development Expenditures per Well ($ MM) (6)=(5)/(4)	Development Expenditures per BPD (M $/BPD) (7)=(6)/(3)
United States	214,585	9,183	43	7,896.7	5,024	1.6	36.8
Canada	21,299	877	41	1,464.7	600	2.4	59.3
Europe	2,128	1,884	886	2,100.3	77	16.2	30.9
Africa	798	525	657	373.7	37	10.1	15.4
Middle East	418	322	769	205.7	45	4.6	6.0
Other Eastern Hemisphere	1,593	1,002	629	966.7	138	7.0	11.1
Other Western Hemisphere	3,419	458	134	306.0	129	2.4	17.7
Total Foreign	29,656	5,068	171	5,417.0	1,026	5.3	30.9

Note: All figures on this table are 3-year weighted averages of 1987-1989 data. "BPD"=barrels of oil equivalent per day. "MM"=millions. "M"=Thousands.
Source: Energy Information Administration, Form EIA-28.

Exploration Trends

One of the major differences between U.S. and foreign exploration spending is the differing roles played by lease acquisition costs. In the United States, exploration leases on Federal lands, including the Outer Continental Shelf, are auctioned. If oil is subsequently discovered, revenues from oil production are subject to a 12.5-percent royalty plus normal U.S. corporate income taxes.

Overseas, lease acquisition costs are usually nominal, with oil firms competing on the basis of the magnitude of the promised exploration program. If oil is subsequently discovered, production is taxed under a special tax regime (particular to each country), often at much higher rates than the normal corporate income tax.

After correcting for the unusual transaction noted above, FRS 1989 unproved property acquisitions accounted for 21 percent of U.S. exploration expenditures, 55 percent of Canadian expenditures, and only 3 percent of exploration expenditures in all other foreign regions.

The focus of FRS exploration investment shifted from Canada and Europe to other regions in 1989. Excluding property acquisition costs, FRS exploration expenditures in 1989 were $3.5 billion, up 3 percent from 1988 levels. Canadian exploration expenditures declined slightly, to $0.7 billion, while expenditures in OECD Europe declined fractionally, to $1.1 billion. African exploration expenditures, on the other hand, rose 24 percent, to $0.6 billion, while Other Eastern Hemisphere expenditures increased 21 percent, to $0.7 billion. Expenditures in the Middle East and Other Western Hemisphere regions declined slightly.

The shifts in exploration expenditures were not mirrored by changes in drilling patterns. The FRS companies drilled 493 exploration wells abroad in 1989, a 19-percent decline from 1988 levels. FRS Canadian exploration drilling declined 29 percent, to only 209 wells, a far greater drop than Canadian exploration expenditures. The decline in Canadian exploration drilling may be a delayed consequence of much lower Canadian dollar oil prices in 1988, which caused companies to reduce their 1989 exploration budgets.

FRS companies drilled a net 284 exploration wells outside of the OECD in 1989, a 9-percent drop. The number of exploration wells in Africa declined 31 percent (36 wells) even as exploration expenditures in Africa climbed 24 percent. Similarly, Other Eastern Hemisphere wells declined 12 percent (96 wells) while expenditures rose 21 percent.

The exact sources of this phenomenon are not clear, but it is most likely linked to changes in the composition of exploration wells (more offshore wells and wells in remote areas), higher drilling costs, and increased expenditures on non-drilling exploration activities such as seismic surveys and site preparation.

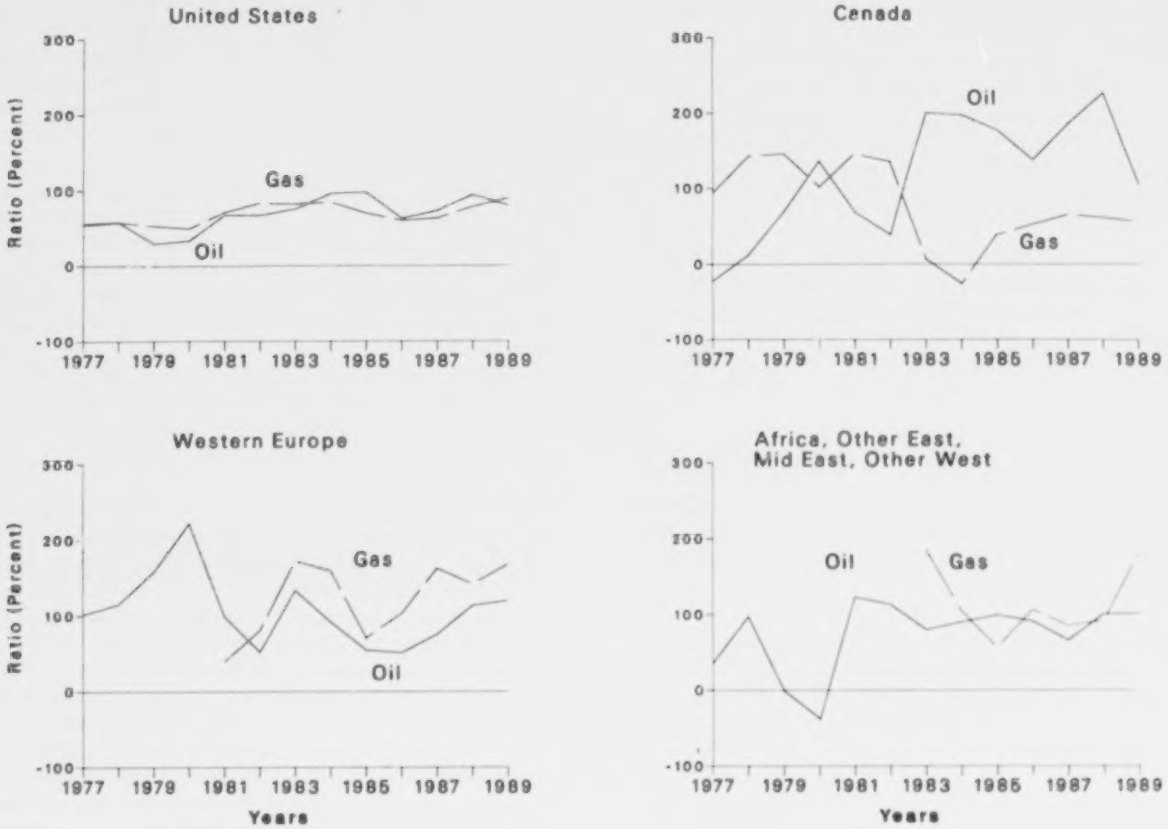
There were a number of exploration programs in remote areas. Exxon and Chevron drilled exploration wells in Chad, in Central Africa, and Chevron resumed exploration in Sudan. Chevron has also made a series of discoveries in the interior of Papua New Guinea (including two successful wildcats in 1989) that will eventually yield commercial production. Many FRS companies are also participating in extensive exploration programs in offshore Western Australia, Indonesia, Malaysia, and Thailand. The bulk of these Other Eastern Hemisphere prospects are offshore.

Figure 32 illustrates the results of the FRS companies' foreign exploration effort. The regional replacement ratios (defined as reserve additions divided by current production) indicate the extent to which FRS oil production is being replaced by additions to reserves. Reserve additions used for computing the graph include discoveries, additions due to improved recovery, and revisions. FRS companies, as a group, spent much of the mid-1980's slowly liquidating their overseas (and U.S.) reserves. This trend has been reversed since 1987, and FRS companies are now adding more oil reserves than they are producing in Western Europe, and are just replacing existing reserves elsewhere. On the other hand, the FRS companies successfully augmented their gas reserves in every region except Canada. In Canada, as noted in the previous sections, the FRS companies have a high ratio of gas reserves to current production. Consequently, the FRS companies may feel no particular urgency about discovering additional Canadian gas reserves.

Exploration Costs

Table 53 shows average exploration costs per successful well. The pattern for exploration costs is generally similar to that for development costs. Per well costs are lowest in the United States and Canada. North American wells cost about half the average of foreign wells, with Middle East and Other Eastern Hemisphere wells the least expensive, and Other Western Hemisphere wells the most expensive.

Figure 32. Ratio of FRS Companies' Additions to Oil/NGL and Gas Reserves to Production by Geographical Area, 1977-1989



Source: Energy Information Administration, Form EIA-28.

However, the quantity of oil and gas discovered mirrored the costs. The average successful FRS exploration well in the United States discovered 2.6 million barrels of oil equivalent. The average FRS Canadian exploration well uncovered only 1.2 million barrels. On the other hand, wells in OECD Europe and in Other Western Hemisphere found four times as much oil equivalent as a U.S. well, while FRS exploration wells in Africa, Asia, and the Middle East uncovered two-to-three times as much oil equivalent.

Regional differences in success rates indicate that North American wells may not find very much petroleum, but, when drilled by the FRS companies, they are more likely to find at least some hydrocarbons than wells in other regions. Outside of North America, the number of wells drilled in each region is relatively small, and the results tend to be volatile from one year to the next. The FRS Middle East success rate was very high (46 percent) in 1989, after having been low in previous years. Europe, the Other Eastern Hemisphere and the Other Western Hemisphere regions have success rates between 30 and 40 percent. African success rates, at only 21 percent, remain notably low.

Exploratory costs, success rates, and exploratory productivity can be put together to compute the exploratory finding costs shown in Tables 53 and 54. A summary of the FRS companies' overall exploration and development activity is shown on Table 55.

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Table 53. Derivation of FRS Companies' Exploratory Finding Costs, 1987-1989

Geographic Area	Exploration Spending (MM $)	Unproved Property Costs (MM $)	Oil & Gas Extensions and Discoveries (MM BOE)	Exploration Cost per Well (MM $)	Extensions and Discoveries per Well (MM BOE)	Success Rate (%)	Finding Cost excl. UPC ($/BOE)	Finding Cost incl. UPC ($/BOE)
United States	4,120	1,460	1,165	3.9	2.5	42.7	3.54	4.79
Canada	591	351	152	2.2	1.2	47.4	3.89	6.20
OECD Europe	1,116	114	336	11.2	10.3	32.9	3.32	3.66
Africa	473	26	58	11.3	6.6	21.1	8.17	8.62
Middle East	172	10	49	8.6	7.0	34.8	3.51	3.71
Other Eastern Hemisphere	575	73	248	6.5	7.4	37.5	2.32	2.62
Other Western Hemisphere	292	3	77	10.9	9.2	31.7	3.81	3.85
Total Foreign	3,219	578	919	5.9	4.2	39.9	3.50	4.13

Note: All data are three year averages, 1987-1989. UPC = Unproved Property Acquisition Costs (Column 2). BOE = Barrels of Oil Equivalent (includes natural gas on an energy equivalent basis). MM = millions.
Note: "Unproved Property Costs" exclude a $250 million unusual item in the Eastern Hemisphere Region.
Source: Energy Information Administration Form EIA-28.

Table 54. FRS Companies' Finding Costs By Geographic Area, 1984-1989
(Dollars Per Barrel of Oil Equivalent)

Geographic Area	1984	1985	1986	1987	1988	1989
United States	8.57	8.02	7.13	6.76	5.73	4.79
Canada	4.85	3.41	3.79	2.93	5.02	6.20
Europe	3.64	3.60	4.41	3.61	3.65	3.66
Africa	7.22	9.49	10.08	10.29	8.89	8.62
Middle East	4.27	7.31	4.49	4.74	3.83	3.71
Other Eastern Hemisphere	11.95	9.13	6.87	5.77	5.39	2.62
Other Western Hemisphere	5.63	2.99	2.56	3.12	3.56	3.85

Note: 3-Year Moving Average.
Source: Energy Information Administration, Form EIA-28.

Finding costs should be used with care. Initial oil reserve estimates made at the time of discovery are usually subject to revisions in subsequent years. Further, oil exploration includes a mix of high-risk pure exploration wells and low-risk appraisal wells. Extensive appraisal drilling programs will tend to depress finding costs. Further, companies tend to "book" new reserves only when development is firmly planned. In the United States and Canada, there is rarely a major time lag between discovery and exploitation. Overseas, long delays between discovery and exploitation are common, which tends to lengthen the interval between drilling a successful well and adding new reserves to a company's account.

Table 55. Foreign Exploration and Development Activity for FRS Companies, 1989

Foreign Petroleum Activities	Total	Canada	OECD Europe	Middle East	Africa	Other Eastern Hemisphere	Other Western Hemisphere
				(number of wells)			
Wells Completed							
FRS Companies	1,214	451	188	72	75	273	155
Percent Change	-35.6	-59.4	-2.3	0.6	-23.1	10.1	-6.8
Foreign Industry[a]	10,496	5,610	645	594	288	1,084	2,275
Percent Change	-27.3	-35.1	-29.8	58.0	-20.4	-23.2	-16.3
				(million dollars)			
Exploration & Development Expenditures							
FRS Companies	14,128	6,266	3,539	406	1,024	2,284	609
Percent Change	8.3	16.0	-18.1	8.0	21.9	66.8	-17.1
				(percent)			
1989 Distribution of Expenditures by FRS Group							
Top Four	100.0	59.7	19.7	[b] 5.0		13.3	2.4
Five Through Twelve	100.0	15.4	30.1	[b] 22.3		22.8	9.4
All Other	100.0	31.4	94.9	[b] 7.2		14.8	1.6
All FRS	100.0	44.4	25.0	[b] 10.1		16.2	4.3
				(million barrels)			
Oil Reserve Interests[c]							
FRS Companies	13,263	2,714	3,961	1,847	1,597	2,317	829
Percent Change	-0.2	-1.3	3.8	-2.0	0.4	-4.0	-0.6
				(billion cubic feet)			
Gas Reserve Interests[d]							
FRS Companies	68,168	14,488	34,283	597	158	17,007	1,634
Percent Change	1.9	1.3	-1.2	2.2	-10.6	10.7	-8.8

[a] Foreign industry levels defined as total activity outside of the United States except for the People's Republic of China, the Soviet Union, Cuba, and the Eastern Europe Bloc. Yugoslavia is excluded from Foreign Industry due to nonavailability of data.

[b] Africa and Middle East regions are combined to avoid disclosure.

[c] Includes net ownership interest reserves (88.5 percent) and "Other Access" reserves (11.5 percent). Other access reserves include proportional interest in investee reserves and foreign access reserves.

[d] Includes net ownership interest reserves (75.6 percent) and "Other Access" reserves (24.4 percent). Other access reserves include proportional interest in investee reserves and foreign access reserves.

Note: Sum of components may not equal total due to independent rounding.

Sources: FRS companies: Energy Information Administration, Form EIA-28. Industry data: *World Oil* (August, 1990), p. 20.

Figure 33 and Table 54 illustrate regional trends in finding costs. Since 1984, Africa has had the highest finding costs in the world, above $8 per barrel of oil equivalent. Very high per well costs have combined with low exploration success rates to drive up finding costs. However, delays in recording new discoveries has also contributed to the high level of exploratory finding costs in Africa.[87]

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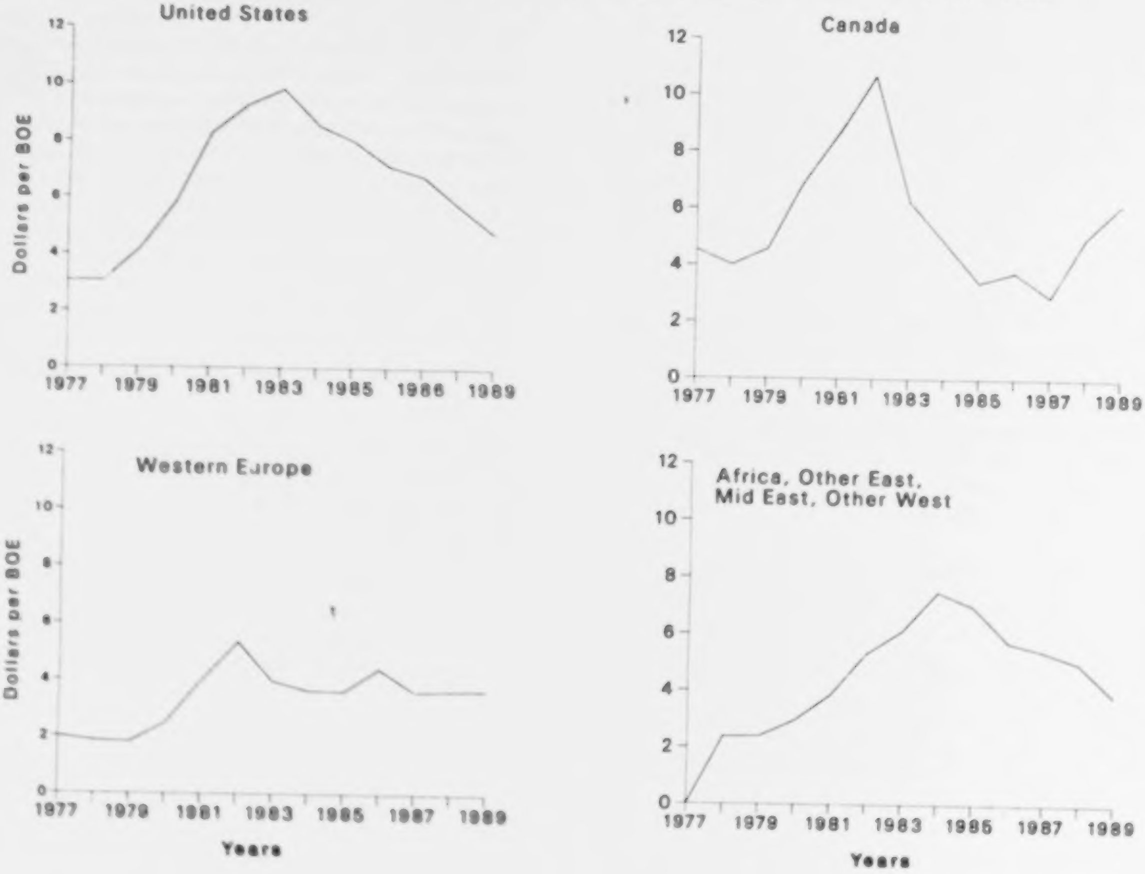
[87] Several FRS companies have had significant successful exploration programs in Africa for which reserves have not yet been booked. USX's Marathon Oil unit expects to begin production from new discoveries in Egypt and offshore Tunisia in 1990-91, but has yet to book any reserves. Exxon reported that "reserves attributable to oil and gas discoveries in Australia, Canada, Chad, France, Germany, Indonesia, Malaysia, the Netherlands, Norway, Thailand, the United Kingdom, the United States and the Yemen Arab Republic were not considered proved as of year-end 1989 due to geological, technological, and economic uncertainties and therefore are not included in the tabulation of proved reserves." (Exxon Corp., *1989 Financial and Statistical Supplement to the Annual Report*, p. 48.)

Figure 33. FRS Companies' Cost of Finding Hydrocarbons by Geographical Area, 1977-1989



Source: Energy Information Administration, Form EIA-28.

U.S. finding costs, which were exceptionally high in the early 1980's, have steadily declined below $5 per barrel, while Canadian finding costs, which dropped to only $2.93 per barrel of oil equivalent in 1987, have doubled to over $6 in 1989.

Finding costs in Europe have been remarkably stable, at about $3.60 per barrel, for most of the past five years. Despite high well costs, high per well discovery rates and stable success rates continue to make North Sea exploration relatively attractive.

Finding costs in Other Eastern Hemisphere halved in 1989, to only $2.62 per barrel of oil equivalent. Much of this drop was attributable to Exxon, which booked 1.8 trillion cubic feet of new gas reserves in the region during 1989.[88] Exxon, as noted above, has vigorous exploration programs in Australia, Indonesia, Malaysia, and Thailand. However, it is likely that the bulk of the new reserves can be attributed to the Jerneh gas field in offshore Malaysia, which Exxon will develop to supply domestic gas markets in Malaysia and Singapore.[89]

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[88] Exxon Corp., *1989 Annual Report*, p. 43.
[89] Exxon Corp., *1989 Annual Report*, p. 12.

Foreign Oil and Gas Taxation

FRS companies' foreign operations have been heavily weighted towards Canada and OECD Europe. Finding costs and production costs, however, tend to favor exploration and production outside the OECD countries. The actual pattern of FRS investments would be inconsistent with the pattern of costs, were it not for the heavy taxes levied on oil production outside of the OECD states.

Outside of OECD, taxes may be a more important determinant of the FRS companies' costs than direct production costs. Taxes can also be changed. In the wake of the 1986 oil price collapse, many host Governments significantly reduced their taxes on foreign oil companies in an effort to forestall reduced investment.[90] The success of this effort has been reflected in the shifts in FRS investments observed over the past two years.

However, with the higher prices experienced in 1989, there was little action by host Governments to further reduce tax rates. The average income tax rate experienced by the FRS companies on foreign production was 54 percent in 1988 and 56 percent in 1988. It is possible to compute marginal tax rates by dividing the change in pre-tax income by the change in income taxes. The marginal income tax rate on foreign production, computed on this basis, was 69 percent.

It is also possible to compute a total foreign tax rate, including royalties and production taxes. The 1988 average total tax rate was 61 percent, while the 1989 average total tax rate rose to 62 percent. The marginal total tax rate was 66 percent. Royalties and production taxes declined from 1988 to 1989 (see Table 51), possibly because foreign oil production declined, even though prices increased.

These tax rates are considerably higher than those levied on U.S. production income. It is not possible to decompose income taxes by region using the FRS data, but several companies report some regional detail.[91] Typical income tax rates for Canada are about 45 percent (Chevron and Mobil), while income taxes for European production operations range from 37 percent (Texaco) to 61 percent (Amoco). Exxon and Chevron reported European tax rates of about 50 percent. On the other hand, income tax rates for non-OECD operations are considerably higher. Chevron reported income tax rates for its African operations (including production from OPEC-member Nigeria and Angola) of 85 percent, which is consistent with published information about its production agreement with the Nigerian Government. Gas-rich Unocal reported its "Far East" operations to have a 36 percent tax rate. Exxon reported tax rates for "Africa and the Middle East" at 65 percent, and "Australia and the Far East" at 46 percent. Mobil reported non-OECD tax rates as a group at 66 percent.[92]

Foreign Refining/Marketing

During the last 2 years, foreign refining/marketing profitability was slightly less than in the United States. However, growing demand in the Far East should boost foreign refining/marketing profitability over the next few years. The fast-growing nations of the Far East account for over half of new distillation capacity construction.[93] The FRS companies, particularly Chevron and Texaco via their Caltex joint venture, are likely to benefit from growing demand in this region.

The FRS companies' foreign refining/marketing income fell by 25 percent to $1.8 billion in 1989 (Table 48). The fall was primarily due to lower margins and reduced refinery output. Margins were squeezed when refined product prices failed to keep pace with crude oil price increases. The operating margin fell by 15 percent from 1988 to 1989.[94] Changes in product composition also tended to increase operating expenses.

Primarily, this resulted from a sharp increase in unleaded gasoline consumption in Europe, as several countries adopted tax policies to discourage leaded gasoline consumption. Texaco, for example, reported that in the United Kingdom unleaded gasoline increased from 3 percent of total gasoline at the beginning of 1989 to nearly 30 percent by the end of the year.[95] However, the FRS companies continued to produce a substantially lower percentage of gasoline in their foreign refineries than they did in the United States. In 1989, gasoline accounted for 29 percent of foreign refinery output volume and 45 percent of U.S. refinery output volume (Tables B45 and B46).

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[90] For a discussion of reduced tax rates in the 1986-1988 period, see last year's issue of this publication, *Performance Profiles of the Major Energy Producers 1988*, pp. 76-79.

[91] Information on regional oil and gas production tax rates is drawn from the following corporate sources: Amoco Corp., *Annual Report 1989*, p. 48, Chevron Corp., *1989 Annual Report*, p. 58, Exxon Corp., *1989 Financial and Statistical Supplement to the Annual Report*, pp. 18-19, Mobil Corp., *Financial and Operating Statistics 1989*, pp. 18-19, Texaco, Inc., *Annual Report 1989*, p. 63, and Unocal Corp., *Annual Report 1989*, p. 60.

[92] Corporate regional break-downs also produced some oddities. USX reported that overseas operations were a net source of tax credits, while Texaco reported non-OECD tax rates for the Other Western Hemisphere and Other Eastern Hemisphere regions at levels above 110 percent.

[93] *Petroleum Economist*, September 1990, p. 31.

[94] The operating margin is calculated by subtracting general operating expenses from operating revenue and dividing by refinery output.

[95] Texaco, Inc., *Annual Report to Stockholders*, 1989, p. 8.

Additions to net investment in place increased by 0.9 percent to $3.4 billion in 1989 (Table 49). However, Exxon's acquisition of Texaco Canada accounted for most of the increase. Excluding mergers and acquisitions, additions to net investment in place would have fallen by 43 percent (Table 49). Some estimates place required European refinery investments at $6 billion before the end of the century.[96] These investments will be required to further reduce leaded gasoline output, lower diesel fuel sulfur content, and process heavy fuel oil into lighter products such as gasoline and diesel fuel. Interestingly, most European countries tax leaded gasoline at higher rates than unleaded to reduce leaded gasoline consumption. As more European consumers turn to high-octane unleaded gasolines, refiners may turn to imports for incremental supplies.

Several refinery transactions involving the FRS companies occurred in 1989. Texaco's sale of Texaco Canada to Exxon involved two refineries. Texaco also transferred the capacity of a European refinery to a new joint venture in the Netherlands. Mobil disposed of its South African assets, which included a refinery. Coastal purchased the former Exxon refinery from the government of Aruba and planned to operate 150 thousand barrels per day of distillation capacity. Overall, FRS companies' foreign refinery distillation capacity fell from 4.6 million barrels per day in 1988 to 4.5 million barrels per day in 1989 (Table 56). The FRS companies' foreign refinery capacity has fallen every year since the late 1970's. Most additions to FRS refinery distillation capacity are likely to be in the Far East, since that is where the bulk of increased refined product demand is likely to be.

International Marine

For FRS companies, transportation revenues for the international marine segment were up 5 percent in 1989, while operating expenses rose 4 percent (Table 57). The international marine segment of FRS companies was the most profitable of all FRS operations in 1989. Earning a 12-percent return on investment in 1989, the international marine segment also realized its most profitable year since at least 1977. In 1988, FRS international marine operations also saw a positive return, of 7 percent, after experiencing losses averaging $280 million for 6 of the previous 7 years (Figure 26).

Increasing world oil consumption has been largely responsible for the improvement in the finances of tanker operators. Increased oil consumption has also caused the recent tanker fleet expansion. In 1989, ocean-going trade (both FRS and non-FRS) in crude oil and petroleum products rose to 30 million barrels per day from 27 million barrels per day in 1988.[97] Over the same period, U.S. imports of crude oil and petroleum products rose by 1.5 million barrels per day.[98] Much of the increase in U.S. imports came from some of the nation's most distant suppliers, adding further to tanker demand. In particular, U.S. imports from Arab OPEC countries rose 16 percent in 1989. Asia has been another source of rapidly increasing demand for oil imports in recent years. For Asian countries, imports of crude oil rose 7 percent over their 1988 levels.[99]

For the international marine industry, by almost all measures, 1989 proved to be a very good year. In 1989, global worldscale tanker freight rates reached a 16-year peak and were 18 percent higher than the previous year's rates.[100] This rise in freight rates was accompanied by a 13-percent rise in the level of tanker employment and a near doubling of global new tanker orders.[101] For FRS companies' international marine operations, additions to investment in place rose to $227 million in 1989 from $158 million in 1988 (Table 57). This growth in investment was one sign of the extent to which FRS companies were expanding their international tanker fleets in 1989.

Some FRS companies made sizable additions to their international tanker fleet in 1989. Chevron, for example, added a net 3 million barrels capacity to its controlled fleet by chartering three additional foreign tankers in 1989. Chevron also signed contracts for the construction of four new 150,000 dead weight tons (dwt) carriers. The company took both actions in response to strong tanker demand and increased international marine segment profits.[102] Further, in 1989, Amoco took delivery of its third 80,000 dwt ocean-going vessel, its fifth new vessel in the last 3 years.[103]

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[96] Roger Vielvoye, "Unleaded Gasoline Sales Still Rising in Most European Markets," *Oil and Gas Journal*, August 27, 1990, p. 15.
[97] British Petroleum Company, *BP Statistical Review of World Energy*, (London, England, July 1989 and June 1990), p. 18.
[98] Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109(90/05), (Washington, D.C., July 25, 1990), Table S3.
[99] British Petroleum Company, *BP Statistical Review of World Energy*, (London, England, June 1990), p. 8.
[100] *World Tanker Review*, (London, England, 31 July through 31 December, 1989) p. 29.
[101] *Oil and Gas Journal*, (Tulsa, OK, May 7, 1990), p. 53.
[102] Chevron Corporation, *Annual Report 1989*, p. 24 and *Supplement to the 1989 Annual Report*, p. 44.
[103] Amoco Corporation, *Annual Report 1989*, p. 15.

Table 56. Foreign Refinery Output, Capacity, and Capacity Utilization for FRS Companies and Foreign Industry, 1986-1989

(Thousand Barrels Per Day)

Refining Statistics	FRS Companies			Foreign Industry[b]	All FRS Share (Percent)
	All FRS	Top Four	Other FRS[a]		
1986					
Output[c]	4,096	3,695	401	32,724	12.5
End of Year Capacity	4,638	4,262	376	38,796	12.0
Utilization Rate[d]	67.2	64.9	94.9	84.4	NM
1987					
Output[c]	4,348	3,929	419	32,740	13.3
End of Year Capacity	4,625	4,189	436	39,441	11.7
Utilization Rate[d]	72.2	70.5	90.9	83.0	NM
1988					
Output[c]	4,691	4,306	385	NA	NM
End of Year Capacity	4,608	4,201	407	39,134	11.8
Utilization Rate[d]	77.2	76.8	81.1	NM	NM
1989					
Output[c]	4,428	4,036	392		
End of Year Capacity	4,514	3,957	557		
Utilization Rate[d]	76.6	76.9	73.4	80.3	NM

[a] Five through twelve and all other categories combined to prevent disclosure.

[b] Foreign Industry defined as all areas outside the United States (including Puerto Rico and the Virgin Islands) except the People's Republic of China, the Soviet Union and Eastern European countries considered part of the Soviet Bloc.

[c] For FRS companies, represents output at own refineries for own account and for account of others plus output at other's refineries for own account.

[d] Utilization based on total crude oil throughput at own refineries for own account divided by average annual refinery capacity.

NA = Not available.

NM = Not meaningful.

Note: Capacity and output are in thousand barrels per day.

Sources: FRS companies: Energy Information Administration, Form EIA-28. Industry data: Energy Information Administration, *International Energy Annual 1989*, DOE/EIA-0219(89) (Washington, DC, December 1990).

Table 57. Financial Items for International Marine Operations of FRS Companies, 1978-1989

(Million Dollars)

Financial Items	1978	1983	1988	1989	Percent Change 1988-1989
Revenues					
Transport	3,934	2,246	2,007	2,170	5.0
Other	64	55	15	15	0.0
Total Revenues	3,998	2,309	2,107	2,208	4.8
Operating Expenses	3,976	2,769	2,009	2,088	3.9
Operating Income	22	-460	98	120	22.4
Net Investment in Place[a]	5,364	3,577	1,732	1,759	1.6
Additions to Investment in Place[b]	239	52	158	227	43.7

[a] Property, plant, and equipment (PP&E) plus investments and advances.

[b] Measured by additions to property, plant, and equipment (PP&E) plus additions to investments and advances.

Note: Sum of components may not equal due to independent rounding. Percent change calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

The recent improvement in tanker demand has not been without problems. During the late 1970's and through most of the 1980's, the tanker market was stagnant. As a consequence, many shipyards went out of business. Consequently, a shortage of shipyard capacity has recently appeared. The shipyard capacity shortage has resulted in rapid increases in the price of new tankers as well as growing delays in the ability of remaining shipyards to meet new orders. Estimated VLCC (very large crude carrier) prices rose to $80 million in December of 1989 from $70 million in December of 1988.[104] As recently as 1984, VLCCs sold for as little as half of what they sell for today.

The grounding of the *Exxon Valdez* was the most important financial development for FRS companies' international marine operations in 1989. In 1989, Exxon took $2.5 billion in pre-tax charges as a result of the damages caused by the grounding of the *Exxon Valdez*.[105] This mishap, along with some other well-publicized subsequent oil spills, spurred Congress to act on oil-spill legislation. On July 26, 1990, the House and Senate conferees approved oil-spill legislation--HR 1465. HR 1465 was signed into law on August 20, 1990.

This law calls for major changes in the way tankers operate in U.S. waters.[106] Perhaps the most important of these changes is the requirement to have a complete but incremental phase-in of double-hulled petroleum tankers. By 1995, all newly built vessels would be required to have two hulls. By 2010, all single-hull tankers would be banned. The bill also requires oil spillers to pay for cleaning up oil spills and to compensate parties injured by them. The bill provides that a federal clean-up fund be established to pay for these cleanups. A surcharge on domestic and imported crude oil would underwrite this fund.

FRS companies may be pursuing a number of ways of adjusting to a more strict pollution law. Conoco, a subsidiary of Du Pont, announced that it would no longer purchase single-hull petroleum transportation vessels and placed orders for two 95,000 dwt double-hulled vessels. The chief executive of ARCO has also come out in favor of double-hull vessels.[107] ARCO also announced that in the future it would ship all its oil on its own tankers and that it would seek increased insurance covering liability limits of $1.25 billion per ship.[108] Further, both Shell and British Petroleum have also added additional insurance coverage for tankers carrying company oil.[109]

In contrast, some FRS companies are currently reducing their investments in tanker operations. Both Texaco and Amerada Hess have restricted heavy oil shipments to Maine, a state viewed by shippers as having particularly stringent marine liability laws.[110] Royal Dutch Shell (the parent of Shell) has announced that it would restrict its U.S. shipments to those unloading at the Louisiana offshore terminal.[111] Finally, in 1990 Exxon's Eastern Maritime Ltd. affiliate had agreed to sell all four of its ULCCs (ultra large crude carriers).[112]

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[104] VLCCs are deep draft tankers generally considered to be from 200,000 to 400,000 dead weight tons. ULCCs are considered to be larger than 400,000 dead weight tons.

[105] Exxon Corporation, *Annual Report 1989*, p. 30.

[106] *Congressional Quarterly* (Washington, DC, July 28, 1990), pp. 55-57.

[107] John Holusha, "Breaking Industry Ranks, Conoco Buys 2-Hulled Ships," *New York Times*, April 11, 1990, p. 42.

[108] Matthew L. Wald, "Oil Companies Rethink Risk of Having Tankers," *New York Times*, June 13, 1990), p. 29.

[109] *Oil and Gas Journal*, (Tulsa, OK, March 12, 1990), p. 27.

[110] *Wall Street Journal*, (New York, NY, July 23, 1990), p. B1.

[111] *Oil and Gas Journal*, (Tulsa, OK, July 30, 1990), p. 25.

[112] *Oil and Gas Journal*, (Tulsa, OK, April 16, 1990), p. 24.

7. Coal, Alternative Energy, and Research and Development

Coal

The U.S. coal industry posted another year of modest growth in 1989, despite the side-effects of the lengthy miner's strike against Pittston Corp., which included a number of brief "wildcat" strikes directed against other firms. Although U.S. coal production grew by over 3 percent for the third consecutive year, U.S. consumption of coal rose by only 2 percent, putting downward pressures on coal prices, which declined 1 percent (See Table 58). Coal exports continued to climb, rising 6 percent to 100.8 million tons, the best industry performance since 1982. Coal export prices were also slightly higher, rising 0.6 percent in 1989.[113]

The FRS companies account for about 29 percent of total U.S. production of bituminous coal and lignite. U.S. coal production of the FRS companies rose less than 1 percent in 1989, to 287 million tons (Table 59). The share of low-sulfur Western coal in FRS production continued to rise, while Mid-western high sulfur coal output continued to decline (Figure 34). The largest FRS coal producer is Dupont's Consolidation Coal Company (50 million tons per year), followed by ARCO (31 million tons), Exxon (28 million tons), Shell Oil Company (25 million tons), and Sun Company (23 million tons).[114]

One FRS company, BP America, announced that it was leaving the U.S. coal industry, putting its coal assets up for sale. Some were sold in 1989, and the balance in mid-1990. Several FRS companies also operate overseas coal operations. Exxon Coal produced nearly 6 million tons of coal from its 50-percent share of the Cerrejon mine in Colombia. Exxon also produced 1.6 million tons of coal from a mine in Canada, and 2.8 million tons from two mines in Australia. ARCO coal produced some 8.1 million tons of coal from Australian mines. Unocal sold off its Canadian coal mining operation in 1989, recording a $91 million dollar loss on the sale of its discontinued operation.[115]

FRS companies were able to achieve somewhat higher prices for their coal in 1989, unlike the industry as a whole. The average price paid for FRS coal (calculated as coal segment sales divided by U.S. coal production) rose by 5.6 percent in 1989, to $24.92 per ton (see Table 60). However, because costs rose even more rapidly, operating income declined slightly. The decline in operating income was offset by a decline in the average tax rate from 29 percent to 26 percent, so that after-tax income from continuing operations rose just over 1 percent, to $0.6 billion.

Two FRS companies recorded large write-downs. As noted above, Unocal recorded a loss on the sale of its Canadian coal assets of $91 million, while Sun Company wrote down certain marginally economic coal reserves in the western United States by $74 million.[116] The impact of these two reduced overall after-tax coal sector net income from $0.59 billion in 1988 to only $0.44 billion in 1989. The rate of return, however, on FRS continuing operations improved slightly, from 6.7 percent in 1988 to 7 percent in 1989.[117] The most striking coal-related financial development of 1989, was not, however, the stable financial results achieved by the FRS companies as a group, but the resurgence of FRS investment in the coal sector. Aggregate FRS coal sector investment increased 82 percent, from $0.58 billion in 1988 to $1.05 billion in 1989. The bulk of the increase was accounted for by a threefold increase in investments in foreign coal production. Exxon reported that its investment in foreign coal production rose more than fivefold, to $0.26 billion. Exxon indicated that it purchased a large coal mine in Australia during 1989.

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[113] Energy Information Administration, *Quarterly Coal Report*. January-March 1990, (DOE/EIA-0121(90/1Q) (Washington, DC, August 1990), p. 20.

[114] Dupont Corp., *1989 Annual Report*, p. 26. Atlantic Richfield Company, *ARCO Annual Report 1989*, p. 21, Exxon Corp., *1989 Financial and Statistical Supplement to the Annual Report*, p. 45, Shell Oil Company, *Shell Oil Company 1989 Annual Report*, p. 11, and Sun Company, *1989 Annual Report*, p. 5.

[115] Unocal Corp., *Annual Report 1989*, p. 45.

[116] Sun Company, *1989 Annual Report*, p. 23.

[117] "The rate of return" is defined as after-tax income from continuing operations divided by the sum of net Property, Plant, and Equipment and net investments and advances.

Table 58. Consumption of Fossil Fuels by the Industrial Sector and Electric Utilities, and Prices of Fossil Fuels Delivered to Steam-Electric Utility Plants, 1985-1989

Consumption and Prices	1985	1986	1987	1988	1989	Percent Change 1988-1989
	(quadrillion (10^{15}) Btu)					
Consumption						
Industrial Sector						
Coal	2.760	2.643	2.673	2.828	2.815	-0.5
Natural Gas[a]	7.080	6.693	7.325	7.697	8.127	5.6
Petroleum	7.725	7.953	8.210	8.463	8.321	-1.7
Total Industrial Consumption	17.565	17.289	18.208	18.988	19.263	1.4
Electric Utilities						
Coal	14.542	14.444	15.173	15.850	15.958	0.7
Natural Gas[a]	3.160	2.691	2.935	2.709	2.862	5.6
Petroleum[b]	1.090	1.452	1.257	1.563	1.681	7.5
Total Electric Utility Consumption	18.792	18.587	19.365	20.122	20.484	1.8
	(cents per million Btu)					
Prices						
Electric Utilities[c]						
Coal	164.8	157.9	150.6	146.6	144.5	-1.4
Natural Gas[a]	344.4	235.1	224.0	226.3	235.5	4.1
Petroleum[d]	431.7	243.7	301.1	243.9	289.3	18.6
All Fossil Fuels (Average)[e]	209.4	175.0	170.6	164.3	167.5	1.9

[a] Includes supplemental gaseous fuels.

[b] Includes residual fuel oil, distillate fuel oil, kerosene, and petroleum coke.

[c] Includes steam-electric utility plants with a capacity of 50 megawatts or greater.

[d] Includes fuel oils No. 4, No. 5, and No. 6, and topped crude fuel oil prices.

[e] Includes residual fuel oil prices and light oil (No. 2 fuel oil, kerosene, and jet fuel) prices.

Source: Price data - FERC Form 423; Consumption data - see Note and Sources for consumption section; Energy Information Administration, *Monthly Energy Review*, August 1990, DOE/EIA-0035(90/08)
(Washington, DC, November, 1990), pp. 33, 83, and 107.

Exxon is also working to increase the capacity of its Cerrejon mine, in Colombia.[118] The FRS companies' U.S. domestic coal investment also increased 34 percent, to $0.57 billion in 1989. While this is a considerable gain over 1988, the rate of coal investment remains well below mid-1980's levels, when annual investments routinely exceeded $1 billion.

Coal production capacity of the FRS companies increased 3 percent in 1989, to 322 million tons per annum. Since actual output increased slightly less, the utilization rate declined from 91 percent to 89 percent. FRS coal reserves remain ample: 172 years of production at current rates.

Alternative Energy

The alternative energy segment of FRS companies consists of a variety of operations including production of oil from tar sands, geothermal energy, oil shale conversion, uranium production, solar energy, cogeneration, and coal gasification/liquefaction. In 1986, the last year in which separate data for each of these operations were collected, uranium, Canadian tar sands, and geothermal production accounted for 94 percent of the revenues generated by the alternative energy segment of FRS firms.

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[118] Exxon Corp., *1989 Financial and Statistical Supplement to the Annual Report*, pp. 16 and 45.

Table 59. Production of Coal for FRS Companies and for U.S. Industry, 1985-1989
(Million Short Tons)

Production[a]	1985	1986	1987	1988	1989	Percent Change 1988-1989
U.S. Production						
FRS Companies						
East	82.9	84.0	98.3	108.5	114.0	5.1
Midwest	36.4	41.7	41.7	38.8	37.7	-2.8
West	111.0	101.9	115.3	138.0	135.1	-2.1
Total FRS	230.4	227.6	255.3	285.3	286.9	0.6
U.S. Industry						
East	422.5	424.2	439.7	445.8	458.6	2.9
Midwest	131.5	135.9	138.6	130.2	134.5	3.3
West	324.9	325.9	336.8	370.7	281.6	2.9
Total U.S. Industry	878.9	886.0	915.2	946.7	974.7	3.0
FRS Share (percent)	26.2	25.7	27.9	30.0	29.4	

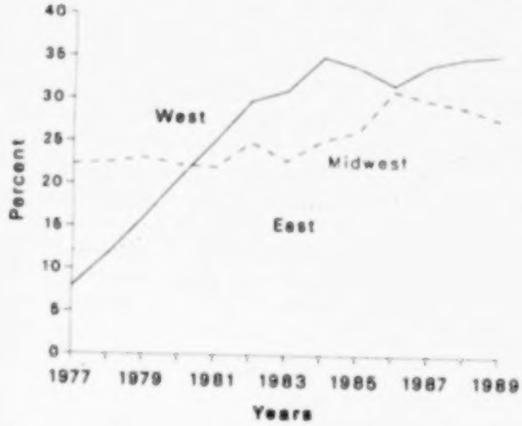
[a] Includes bituminous coal and lignite, excludes anthracite.

Notes: Sum of components may not equal total due to independent rounding. The East region includes Alabama, eastern Kentucky, Georgia, Maryland, Mississippi, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The Midwest region includes Illinois, Indiana, Michigan, and western Kentucky. The west region includes the coal-producing States West of the Mississippi river.

Sources: FRS companies: Energy Information Administration, Form EIA-28. U.S. Industry production: Energy Information Administration, *Coal Production 1989* DOE/EIA-0118(89) (Washington, DC, December, 1990), Table 2.

Figure 34. **FRS Companies' Share of Bituminous Coal and Lignite Production, by Region, 1977-1989**



Source: o Industry Data – Energy Information Administration, *Coal Production, 1989*, DOE/EIA-0118(89) (Washington DC, December 1990. o FRS Companies–Energy Information Administration, Form EIA-28.

For the last decade, demand for alternative fuels has suffered as the price of conventional fuels has remained low. In 1989, the price of alternative fuels had yet to reach profitable levels, causing FRS companies to continue their exit from almost all areas of alternative energy. In that same year, FRS companies' alternative energy operations lost $70 million and by most indications this segment remained the weakest performing of all FRS company operations. The $70 million income loss in 1989, however, marked an improvement relative to the $84 million loss recorded for 1988. This improvement was largely due to higher profitability for tar sand and geothermal operations. Due to these same operations, revenues from FRS alternative energy operations rose 30 percent in 1989, to $1.1 billion (Table 61).

In 1989, the departure from the alternative energy business of FRS firms had a geographic element. Net investment in place for FRS company domestic alternative energy fell 14 percent in 1989, partly as a result of the sale of ARCO Solar. Over the same period, however, foreign net investment remained constant (Table 61). Almost all of the latter category of investment consists of tar-sands operations in Alberta, Canada. In 1989, FRS investments made up the entire share of foreign ownership of Canadian tar-sands operations. Although FRS tar-sands production declined in 1989, the value of this production rose 22 percent due to favorable prices.[119] These favorable prices also were largely responsible for the improvement in FRS company tar-sand income.

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[119] Petroleum Monitoring Agency Canada, *1989 Monitoring Report*, (Ottawa, Ontario, June 1990), Table B12.

Table 60. Financial Items in the Coal Segment for FRS Companies, 1985-1989

Financial Items	1985	1986	1987	1988	1989	Percent Change 1988-1989
			(million dollars)			
Operating Revenue	5,615.3	5,523.4	5,980.0	6,396.0	6,861.0	7.3
Operating Expense[a]	5,048.0	4,972.0	5,314.0	5,601.0	6,083.0	8.6
Operating Income[a]	567.3	551.3	666.0	795.0	778.0	-2.1
Additions to Investment in Place[b]	1,469.8	663.2	637.0	577.0	1,048	81.6
Operating Income/Net PP&E (percent)[a]	6.9	7.1	7.9	9.5	9.4	--
Per-Unit Values[c]			(dollars per short ton)			
Operating Revenue	27.79	26.44	25.22	23.61	24.92	5.6
Operating Expense[a]	25.20	24.07	22.00	20.18	21.91	8.5
Operating Income[a]	2.59	2.37	3.22	3.41	3.01	-11.8
Contribution to Pretax Cash Flow[a] [d]	4.92	4.96	5.58	5.29	5.09	-3.6

[a] Excludes writedowns and other unusual items totaling -$515 million reported by FRS companies in 1986, and -$65 million in 1987.
[b] Measured as additions to property, plant, and equipment (PP&E), plus investments and advances.
[c] Financial items divided by production volumes for FRS companies with more than 90 percent of their coal assets in domestic operations.
[d] Sum of operating income and depreciation, depletion, and amortization (DD&A), divided by production volume.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table 61. Revenues, Income, and Investment in Other Energy for FRS Companies, 1985-1989
(Million Dollars)

Financial Items	1985	1986	1987	1988	1989	Percent Change 1988-1989
Revenues	1,611.4	1,218.7	913.0	811.0	1,054.0	30.0
Operating Income	-62.8	-131.2	-59.0	-124.0	-153.0	NM
Net Income	-311.6	-26.1	18.0	-84.0	-70.0	NM
Net Investment in Place[a]						
Domestic						-14.1
	2,601.5	2,197.6	2,121.0	1,963.0	1,686.0	
Foreign	1,121.6	1,124.1	1,179.0	1,410.0	1,404.0	-0.4
Total	3,723.1	3,321.7	3,300.0	3,373.0	3,090.0	-8.4

[a] Defined as the sum of net PP&E and investments and advances to unconsolidated affiliates.
NM = Not meaningful.
Note: "Other energy" includes nuclear fuel for all years.
Note: Sum of components may not equal total due to independent rounding. Percent change calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

Despite the geothermal segment's improved profitability, FRS companies' involvement in geothermal operations remains uncertain. In 1990, Chevron, one of the few remaining FRS companies with geothermal energy investments, announced the sale of three geothermal operations in Nevada and Utah. Chevron did, however, also announce plans to accelerate geothermal exploration in Indonesia.[120] Further, Unocal, with geothermal operations in California, Indonesia, and the Philippines, recorded revenues from geothermal operations of $190 million in 1989, up from $155 million in 1988. Over the same period, Unocal's geothermal energy income rose to $56 million from $41 million. The gain in income in 1989 was due to a new geothermal power plant coming on stream in February, 1989.[121]

In 1989, Unocal remained the only U.S. company involved in oil shale production. Although oil prices rose in 1989, they never came close to the price level where oil shale (without subsidies) could effectively compete with conventional fuels. However, there have been some encouraging developments which suggest that this area of alternative energy may see additional activity in the future. For instance, Unocal reported improved earnings for its oil shale operations in 1989 due to lower production costs.[122] Further, in 1990, Occidental Petroleum put forth a proposal to enter the oil shale business and the United States Department of Energy awarded Occidental a $740,000 contract to plan an oil shale facility.[123]

The performance of FRS companies' investments in uranium production and solar power production displayed little promise in 1989. The uranium production industry (which consists of both FRS and non-FRS companies) has contracted sharply since the late 1970's. Favorable prices for alternative fuels, a movement away from nuclear power generation, and strong foreign competition were largely responsible for this trend. Although U.S. production of uranium rose slightly in 1989, by almost all other measures, the year 1989 showed little improvement. Uranium prices, uranium industry exploration and development expenditures, and uranium industry employment, all declined substantially from the previous year.[124] The experiences of FRS firms in uranium production closely followed that of the entire uranium industry. Since FRS uranium production peaked at nearly 50 percent of total U.S. production in 1977, all but one FRS company left the industry (Figure 2, Chapter 1). In 1989, Chevron was the only remaining FRS company with uranium production operations; however, in 1990, its Mount Taylor uranium mine, which accounted for a large share of its uranium production, was closed. At the time, Chevron also took charges against its other uranium operations.[125]

The latest FRS company to have abandoned the solar power business was ARCO. In February 1990, ARCO signed an agreement with Siemens AG of West Germany to sell ARCO Solar.[126] In the last few years, both Exxon and Shell have exited the solar power industry leaving Amoco and Mobil as the only FRS companies with solar power investments. At present, the solar power activities of FRS companies involve primarily the manufacture of photovoltaic cells. Companies engaged in solar energy research have made considerable progress in improving the efficiency of photovoltaic cells in recent years. Still, at present, solar power's applicability lies only in a few niche markets. Continuous improvements in both technology and manufacturing techniques appear to hold the key to the future economic viability of this energy resource.

Research and Development

The primary research and development (R&D) efforts of the FRS companies in 1989 were in the areas of oil and gas recovery, chemical and petroleum refining processes, and petroleum and chemical product applications and development. In 1989, 19 FRS companies reported R&D expenditures totaling $3.7 billion (Table 62).[127] This was an increase of $4 million (0.1 percent) from 1988. Although absolute R&D expenditures have fluctuated greatly since 1981, they have remained virtually constant as a percent of operating revenues (Figures 35 and 36).

[120] Chevron Corporation , *Supplement to the 1989 Annual Report*, p. 37.

[121] Unocal Corporation, *Annual Report, 1989*, pp. 18 and 58.

[122] Unocal Corporation, *Annual Report, 1989*, p. 29.

[123] Thomas W. Lippman, "A Lone Hand in Shale Oil Production," *Washington Post*, (August 22, 1990), pp. 9-10.

[124] Energy Information Administration, *Uranium Industry Annual.* 1990, DOE/EIA-0478(89) (Washington, DC, September, 1989), Table ES1.

[125] Chevron Corporation, *Annual Report, 1989*, p. 35.

[126] *The Wall Street Journal*, (New York, NY, February 9, 1990), p. A5A.

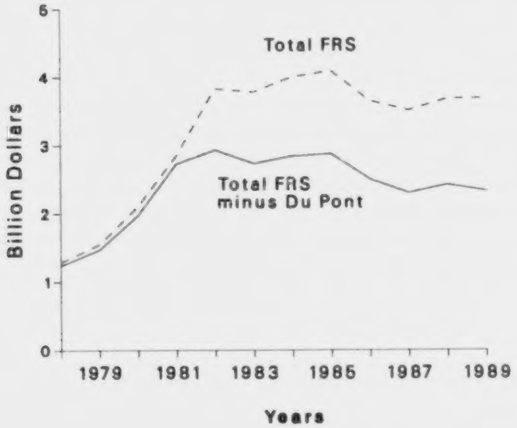
[127] The discussion on research and development includes E.I. du Pont de Nemours (Du Pont); however, Du Pont is not a typical FRS company in that its primary business is chemical production or chemical-based manufacturing. Chemicals are also the primary focus of Du Pont's R&D efforts. In 1989, Du Pont reported in their Securities and Exchange Commission Form 10-K that they spent $1.4 billion on R&D. Most of those funds were expended on various nonenergy activities. Du Pont's R&D represents 37 percent of the total FRS R&D of $3.7 billion in 1989. Its relative R&D commitment plus its emphasis on nonenergy activities affects the distribution of total FRS R&D expenditures. Du Pont, as a chemical company, is representative of that industry in terms of its R&D expenditures (3 to 4 percent of sales), whereas the oil and gas industry historically spends much less on R&D relative to sales (0.7 percent). The basic trends depicted in the R&D figures and tables are maintained with and without Du Pont in the calculation. With Du Pont in, though, nonenergy R&D gains as a percent of total R&D at the expense of both petroleum and other energy, and the R&D to sales ratios are a little higher with Du Pont included.

Table 62. Worldwide Research and Development Expenditures by FRS Companies, 1985-1989 (Million Dollars)

Uses	1985	1986	1987	1988	1989	Percent Change 1988-1989
Petroleum						
Oil and Gas Recovery	801.4	645.3	666.0	726.0	694.0	-4.4
Other Petroleum	536.2	496.4	463.0	496.0	575.0	15.9
Total Petroleum	1,337.6	1,141.7	1,129.0	1,222.0	1,269.0	3.8
Coal, Conventional	23.6	21.2	17.0	18.0	14.0	-22.2
Coal Gasification/Liquefaction	116.7	68.8	47.0	34.0	37.0	8.8
Other Energy[a]	293.4	169.6	91.0	85.0	93.0	9.4
Total Energy	1,771.3	1,401.2	1,284.0	1,359.0	1,413.0	4.0
Nonenergy	2,211.6	2,054.5	2,166.0	2,307.0	2,148.0	-6.9
Unassigned	124.7	124.9	38.0	33.0	142.0	330.3
Total	4,107.5	3,580.7	3,488.0	3,699.0	3,703.0	0.1

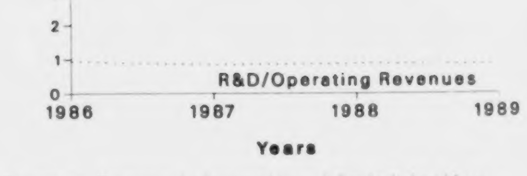
[a] Other Energy includes nuclear, oil shale, tar sands, solar, and geothermal.
-- = not applicable.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Figure 35. Research and Development Expenditures for FRS Companies, 1978-1989



Source: o Du Pont Data: E.I. du Pont de Nemours and Company Annual Reports, 1982-1989. o FRS Companies: Energy Information Administration Form EIA-28.

Figure 36. Research and Development Expenditures as a Percent of Cash Flow from Operations and Operating Revenues, for FRS Companies, 1986-1989

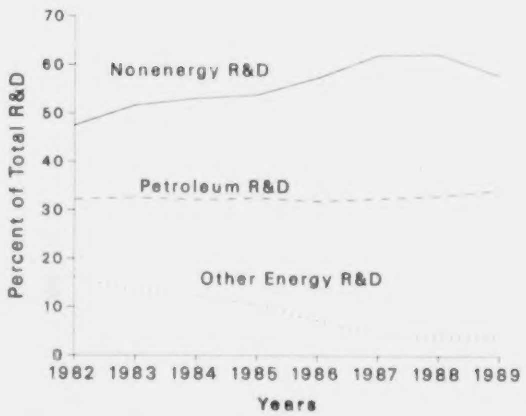


Source: Energy Information Administration, Form EIA-28.

The $4 million increase was attributable to increases in petroleum and all other energy (including coal, coal gasification and liquefaction, nuclear, tar sands, geothermal, and solar) R&D expenditures, which were almost entirely offset by a decline in nonenergy R&D expenditures. Petroleum R&D increased by 4 percent in 1989, to $1.3 billion, which was greater than the previous three years, but still shy of the peak level reached in 1985. All other energy R&D increased by 5 percent in 1989, to $144 million. This increase reversed seven years of declining expenditures. However, it falls far short of the $632 million spent in 1982. Nonenergy R&D decreased by 7 percent in 1989, to $2.1 billion. Most of the decrease was due to a change in the survey group.[128] Little change occurred in the distribution of R&D expenditures among the various R&D categories between 1988 and 1989 (Figure 37). However, in 1989 there was a reversal in the six continuous years of relative increases in nonenergy R&D at the expense of other energy. The nonenergy R&D share of total R&D declined by over 4 percentage points. All other energy and petroleum R&D shares of total R&D increased by 0.2 and 1.2 percentage points, respectively.

The ratio of R&D to cash flow of the FRS companies has been very stable in recent years (Figure 36). However, the changes in distribution of R&D expenditures since the early 1980's among the various R&D activities reported by the FRS companies is explained by expectations for future returns on R&D expenditures. Distribution of applied and developmental research funds (which account for more than 80 percent of total FRS R&D), being a function of expected rate of return on those R&D investments, reflected declining profit expectations by the FRS companies in the non-petroleum energy areas, and increased profit expectations in nonenergy, especially chemicals. Petroleum R&D has remained steady as a percent of total R&D, despite volatile economic conditions in the oil and gas industry, because petroleum is the primary business for most of the FRS companies. The reversal of the nonenergy and other energy trends in 1989 is not expected to be anything more than a temporary adjustment. Other energy expenditures should continue to fall as the FRS companies continue to sell off their interest in those operations. The decline in nonenergy R&D expenditures was primarily related to the change in the FRS group of companies.

Figure 37. Distribution of Research and Development Expenditures for FRS Companies, 1982-1989



Source: Energy Information Administration, Form EIA-28.

The ratio of total FRS R&D to sales in 1989 is comparable to the same ratio for the U.S. total oil and gas industry, as reported both by the National Science Foundation and the annual R&D survey conducted by *Business Week*. Although the average FRS ratio of 0.85 percent in 1989 was slightly higher than the industry's ratio of 0.7 percent, the difference is due to the presence of Du Pont in the FRS group. There is also a direct correlation for the FRS companies between size of company and R&D commitment. In 1989, the ratios for the three FRS company groupings ranked by total assets ranged from 1 percent for the top-third group to 0.5 for the middle-third group to 0.1 percent for the bottom-third group of companies.

In 1988, the latest year for which data are available from the National Science Foundation (NSF), the FRS companies' share of total U.S. energy research was 36 percent. This was a decline of 1 percentage point from 1987.

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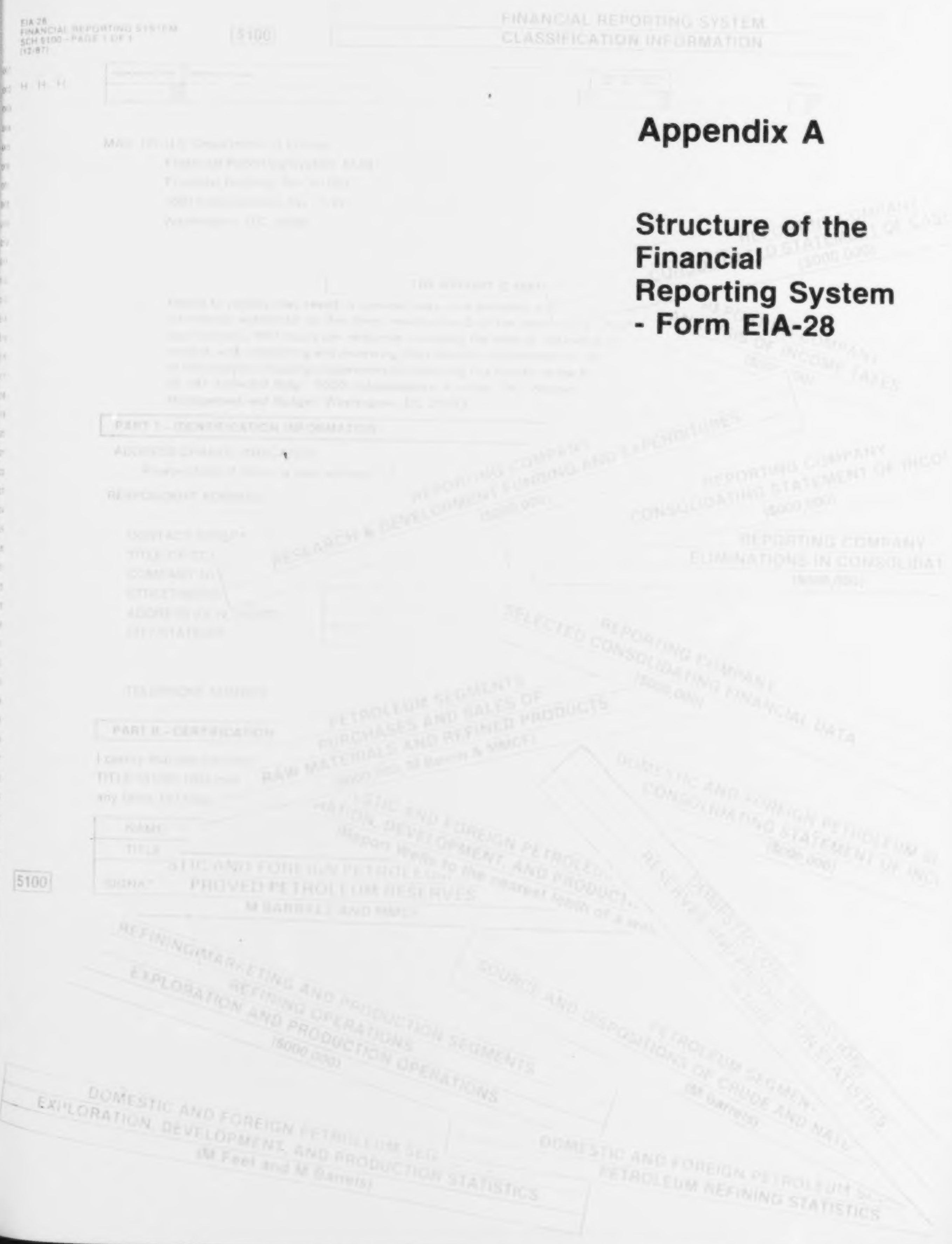
[128] In 1989 Tenneco was dropped from the FRS survey, and Total Petroleum, Ltd. was added. This change in the composition of the FRS companies creates a minor discontinuity in R&D trends due to differences between the two companies. Nonenergy is the area of R&D most affected by this change.



Appendix A

Structure of the Financial Reporting System - Form EIA-28

Appendix A

Structure of the Financial Reporting System - Form EIA-28

Reporting Format

The structure of the FRS data system is designed to permit review of the functional performance of major energy-producing companies in total, as well as by specific functions and geographic areas of operation. The data reported by respondent firms are segregated by line-of-energy activity, as well as by geographic location. The financial reporting schedules in Form EIA-28 are designed to obtain data on revenues, cost, and profits, thereby indicating financial flows and performance characteristics for any given annual reporting period. In addition, the form collects balance sheet data (i.e., accumulated property, plant, and equipment, etc.), along with data on new investment in these accounts. To complement the financial data, a series of statistical schedules are included to trace physical activity patterns and to evaluate several physical/financial relationships.

In greater detail, the structure of the reporting package is as follows:

1. Financial Reporting
    - a. The starting point is the three basic financial statements required by the Securities and Exchange Commission (SEC) Form 10K:
        - i. Consolidating Statement of Income (Schedule 5110)
        - ii. Selected Consolidating Financial Data (Balance Sheets) (Schedule 5120)
        - iii. Consolidated Statement of Cash Flows (Schedule 5131)
    - b. Corporate-wide financial information is first disaggregated by energy type (referred to as lines-of-business) on Schedule 5110 and 5120 as follows:
        - i. Petroleum
        - ii. Coal
        - iii. Other Energy (includes Nuclear)
        - iv. Nonenergy (includes Chemicals)
    - c. Nonenergy data is collected to describe corporate resource investment strategy and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.
2. Operating and Statistical Information
    - a. For each type of energy activity, complementary operating information is obtained through the following schedules:
        - i. Petroleum (5212-5246)
        - ii. Coal (5341)
    - b. The schedules are designed to correspond to the financial information so that level of effort in the financial sense can be compared to physical results.
3. Complementary Schedules
    - a. Examine corporate research and development funding priorities (Schedule 5111)
    - b. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)
    - c. Monitor raw material acquisition and refined product disposition strategies of FRS companies (5211-5212)
    - d. Trace changes in reserves for petroleum (5246) and coal (5341).

Petroleum Segment Overview

The petroleum line of business is further disaggregated into segments.[129] These segments are presented as though each were a separate entity, with recognized limitations, entering into transactions with other segments and third parties.

The following lists each segment within the petroleum line of business and includes a brief description of that segment's principal revenue-generating product or service. (Further detail, on the FRS petroleum segments may be found in the section on "FRS Petroleum Supply and Trading Function" and "FRS Income Taxes.")

1. *U.S. Production.* Production and sales of U.S. crude, natural gas, and natural gas liquids. For FRS purpose sales of U.S. crude can be only made to the U.S. refining/marketing segment. Natural gas and natural gas liquids can be purchased from or sold directly to U.S./foreign third parties, unconsolidated affiliates, and other U.S./foreign segments.
2. *U.S. Refining/Marketing.* Purchases raw materials from U.S. production, foreign refining/marketing and third parties for refining and/or sale of third parties. The segment also purchases directly from foreign production for companies that do not have foreign refining/marketing and imports all foreign purchases.
3. *Rate Regulated Pipeline.* Transports crude, natural gas, and natural gas liquids through Federal or State regulated pipeline operations.
4. *Foreign Production.* Production and sales of foreign crude, natural gas, and natural gas liquids. Sales are made to the foreign refining/marketing segment unless the company does not have foreign refinery operations and imports all foreign purchases. Companies that meet these criteria may sell directly to U.S. refining/marketing.
5. *Foreign Refining/Marketing.* Purchases raw materials from foreign production segments and U.S. refining/marketing segments, refines and sells to third parties, and to U.S. refining/marketing segments.
6. *International Marine.* Provides high seas marine transportation of foreign source crude for third parties and for foreign and U.S. source crude.

Selection of FRS Reporting Companies

Twenty-seven companies were initially notified of a requirement to file Form EIA-28. This group was chosen from the top 50 publicly-owned domestic crude oil producers, in 1976, who had at least 1 percent of either the production or the reserves of oil, gas, coal, or uranium; or 1 percent of refining capacity or petroleum product sales. General Electric (GE) was originally included in the group, because of its interest in Pathfinder Mines Corporation (Pathfinder), which was a uranium-producing company. However, GE did not file Form EIA-28 because Pathfinders's financial statements were not consolidated into the financial statement of GE as a FRS reporting company. Pathfinder was not included in the FRS database.

Mergers, acquisitions and spinoffs together with the selection criteria applied to 1982 data resulted in the list of companies shown in the tabulation below.

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[129] The other lines of business (Coal, Other Energy, and Nonenergy) were also disaggregated into segments but only through 1986.

Companies Reporting to the Financial Reporting System, 1977-1989:

Company	1977-81	1982	1983-84	1985-86	1987	1988	1989
Amerada Hess Corporation	X	X	X	X	X	X	X
American Petrofina Inc.	X	X	X	X	X	X	X
Amoco Corporation[a]	X	X	X	X	X	X	X
Ashland Oil Inc.	X	X	X	X	X	X	X
Atlantic Richfield Co. (ARCO)	X	X	X	X	X	X	X
BP America[b]					X	X	X
Burlington Northern Inc.[c]	X	X	X	X	X		
Burlington Resources Inc.[c]						X	X
Chevron Corporation[d] [e]	X	X	X	X	X	X	X
Cities Service[f]	X	X					
Coastal Corporation	X	X	X	X	X	X	X
Conoco[g]	X						
E.I. du Pont de Nemours and Co.[g]		X	X	X	X	X	X
Exxon Corporation	X	X	X	X	X	X	X
Getty Oil[h]	X	X	X				
Gulf Oil[e]	X	X	X				
Kerr-McGee Corporation	X	X	X	X	X	X	X
Marathon[i]	X						
Mobil Corporation[j]	X	X	X	X	X	X	X
Occidental Petroleum Corporation[f]	X	X	X	X	X	X	X
Oryx Energy Company[k]						X	X
Phillips Petroleum Company	X	X	X	X	X	X	X
Shell Oil Company	X	X	X	X	X	X	X
Standard Oil Co. (Ohio) (SOHIO)[b]	X	X	X	X			
Sun Company[k]	X	X	X	X	X	X	X
Superior Oil[j]	X	X	X				
Tenneco Inc.[l]	X	X	X	X	X	X	
Texaco Inc.[h]	X	X	X	X	X	X	X
Total Petroleum (North America) Ltd.							X
Union Pacific Corporation	X	X	X	X	X	X	X
Unocal Corporation	X	X	X	X	X	X	X
USX Corporation[i]		X	X	X	X	X	X

[a] Formerly Standard Oil Company (Indiana).

[b] In 1987, BP America acquired all shares in Standard Oil Company (Ohio) that it did not already control.

[c] Burlington Resources was added to the FRS system and Burlington Northern was dropped for 1988. Data for Burlington Resources cover the full year 1988 even though that company was not created until May of that year.

[d] Formerly Standard Oil Company of California.

[e] Chevron acquired Gulf Oil in 1984 but separate data for Gulf continued to be available for the full year 1984.

[f] Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.

[g] Du Pont acquired Conoco in 1981. However, separate data for Conoco were available for 1981 and Du Pont was not included in the FRS system until 1982.

[h] Texaco acquired Getty in 1984 but Getty was treated as a separate FRS company for that year.

[i] U.S. Steel (now USX) acquired Marathon in 1982.

[j] Mobil acquired Superior in 1984 but both companies were treated separately for that year.

[k] Sun Company spun off Sun Exploration and Development Company (later renamed Oryx Energy Company) during 1988. Both companies are included in the FRS system for 1988 and some degree of double counting therefore exists for that year.

[l] Tenneco sold its worldwide oil and gas assets and its refining and marketing assets in 1988. A number of other FRS companies purchased about 70 percent of Tenneco's assets.

"X" indicates that the company was included in the FRS system for the year indicated.

Source: Energy Information Administration, Form EIA-28.

Data Quality Assurance Program

The data quality assurance program encompasses EIA's efforts to ensure the quality and integrity of FRS data. These efforts are evidenced in the design of the form and in the procedures applied to checking the data, i.e., the desk audit and machine programmed checks.

Forms Design

The Securities and Exchange Commission (SEC) Form 10K contains financial statements certified by independent certified public accountants. These financial statements, and the entire text of the annual report and Form 10K, are reviewed by the SEC staff. With these procedures and requirements, the SEC's intention is to provide the investing public with assurances that data filed on Form 10K are accurate and are in accordance with generally accepted accounting principles.

In order to take advantage of the SEC review and the certification by Certified Public Accountants, the FRS Form EIA-28 is designed in a multitier structure, which presents both the Form 10K figures and statistics and the more detailed data required by the FRS system. The top level FRS tier corresponds to Form 10K; the second level tier is the first level disaggregated into the different sources of energy (e.g., petroleum, coal, etc.); and the third level tier is the second level disaggregated into the specific functional line-of-business segments within petroleum. (See the Petroleum Segment Overview section at the beginning of this appendix, which describes the FRS segments in detail.) The fourth level tier provides further detail within the individual segments, for example, the details of the patterns of petroleum raw materials purchased and sold. Therefore, the low level tiers can be aggregated to each successively higher tier until the consolidated Form 10K figures are reached. In this way, the more detailed FRS figures are locked into the more aggregated figures already reported publicly to the SEC and to individual company shareholders.

Review Procedures

Detailed desk review and machine editing procedures have been established for the incoming FRS data. The end product of each review is the issuance of a letter to the reporting company containing questions regarding data elements. The reporting companies are instructed to respond to each question, either by explaining the item or by amending any incorrect schedule. When an amended schedule is received, it is reprocessed like the original with the full range of desk and machine checks. The result of this process is a relatively clean data base from which to compile the output reports.

The FRS review procedures include:

- Machine programmed checks for mathematical accuracy (e.g., addition and substraction);
- Machine programmed checks to insure that corresponding schedules are correctly cross-referenced;
- Comparing reported FRS data to information from each company's Form 10K and annual report;
- Comparing reported data (e.g., average cost per foot drilled) for an individual FRS company to the average for all FRS reporting companies, to ascertain any variance; and
- Comparing reported data to other related data series to ascertain any unusual variance.

Machine Programmed Checks

There are 792 machine programmed checks for mathematical accuracy which ensure that each horizontal and vertical total equals the sum of the amounts within each line or column. These checks also ascertain that the amounts within a certain section of a schedule equal the amounts of the same description within a different schedule. Thus, these checks ensure the mathematical accuracy of the schedule.

Cross-referencing between schedules is performed through machine programmed checks. These checks are performed to ensure accuracy and consistency between different schedules. For example, if a respondent indicated on Schedule 5210 that the U.S. production segment charges for depreciation, depletion and amortization were a certain amount, a comparison would be made with Schedule 5210 to ascertain that the amount reported on 5210 agreed with the amount on 5120. There are 51 of these checks performed on each respondent's submission. Since the number of errors noted during these checks is an indicator of respondent misunderstanding of the form, existing and potential problems are identified. The FRS review staff can then focus most of their attention on specific areas where data accuracy may be more of a problem.

Comparison with Audited Information

This is the detailed comparison of the data submitted to the FRS system with that contained in the Form 10K report and the annual report to shareholders.

As stated previously, the Form 10K report and the annual report contain financial information that has been examined and reported by an independent certified public accountant. This financial information along with textual and statistical information has also been reviewed by the SEC staff, which includes not only accountants, lawyers, and financial analysts, but also petroleum and mineral resource engineers. Hence, the data contained in these documents are considered a valuable reference in connection with the quality of FRS data.

The data contained in each respondent's submission is compared to the Form 10K and the annual report material using a detailed audit program. Each audit program step is performed by trained auditors with accounting degrees, supervised by CPA's with experience in auditing medium to large public companies.

These comparisons involve checking elements in both the financial and physical information areas (i.e., production, reserves, refinery statistics, etc.). Direct comparisons are made of specific data elements of the FRS form with corresponding items on Form 10K or in the annual report. Indirect comparisons deal with information that is mentioned in Form 10K and the annual report but which is not quantified sufficiently for direct matching with FRS data. For example, if a respondent's annual report discussed an investment in coal, appropriate entries would be expected on the FRS schedule for coal.

Comparison Procedures

The FRS review procedures also include two other types of comparisons. The first type of comparison is made against prior year FRS data. These procedures assure consistency and reasonableness across reporting years.

The second type of review involves comparison to other related data series. Information contained in the FRS system is compared to data available from other DOE systems and published data, such as State mining surveys.

The FRS review and audit procedures, described above, lead to the issuance of a set of questions to the reporting companies each year. Response to these questions generates substantial interchange between the energy company staffs and the FRS staff. From this interchange the company personnel have acquired a better understanding of the unique aspects of the FRS system, and the FRS staff has learned more about each reporting company. Also achieved has been a greater understanding of reporting company accounting and reporting practices and how they might affect the published FRS aggregate data.

Statistical Disclosure Avoidance Procedures

During the development of this report, a systematic set of procedures that are intended to prevent the disclosure of "individually identifiable energy information" has been applied. Tables that appear in this report provide summary, rather than company, level information. In most cases, the level of summarization is for all FRS companies. In certain cases, subcategories have been established that break the reporters into size or other descriptive classes. Each table has been screened to ensure that no statistical disclosure will occur.

A large number of summary computer reports, generated from a single selected data base, provide the basis for the tables that are published in this report. In conjunction with the summary reports, a parallel set of cell count reports were produced that tabulate for each report cell the number of nonzero values that were aggregated to produce the summary value. The cell count reports were then reviewed to identify whether potential disclosure problems would result from having an insufficient number of reporters or from having values that primarily represent dominant companies in a particular energy sector or activity.

If potential disclosure problems were identified, the tables were restructured to combine values or groups of individual cells in the tables so that the resultant tables were essentially disclosure free.

Financial Analysis Guide

Indicators of Financial Performance

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected which are designed to show the dollar values and geographic distribution of production, profits, funds generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same, or similar, to indicators which have been in regular use by financial analysts and economists for many years. However, to avoid potential misunderstandings, a discussion follows of the measures used, their significance, and their limitations.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on "generally accepted accounting principles" (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations and the accumulated assets, liabilities, and owners' equity of individual business enterprises. The two primary problems one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions are not reflected). Both of these can cause a degree of noncomparability of reported data, across companies in the case of accounting methods, and through time in the case of historical cost accounting. In spite of these problems, the data are still regarded as meaningful, especially for trend analysis. (For a further discussion of these two problems see the Accounting Practices section of this appendix.)

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP this measure is based on arms-length transactions with third parties. However, in the FRS system the concept of sales has been extended to include sales from one segment to another. In such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation. The establishment of the FRS line-of-business segments, the definition of sales (trading function), and the necessary categories of nontraceable and eliminations are discussed more fully in the Accounting Practices section of this appendix.

Profits are the measure of financial return for company activities. In the FRS system, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits, and is used after the deduction for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Excluded from this figure are such items as income taxes, and interest income and expense. Interest expense is not allocated to the segments because it is a "corporate level" item for FRS system purposes. (This is explained more fully in the Accounting Practices section of this appendix.) Contribution to net income is meant to be the equivalent of net income for individual segments. The term net income is not used for individual segments since several corporate level items are not allocated to the segment level.

"Cash flow from operations" is presented for the consolidated company and is intended to be conceptually close to "cash generated from operations." Cash flow from operations is calculated by taking net income and adding back the noncash components of net income, such as depreciation, depletion, amortization, and deferred taxes. It is a useful concept in judging the amount of resources, in the short run, that a corporation is generating from its operations. This is useful not only in judging solvency, but in ascertaining which resources are available for new investment. It is also useful as an adjunct to net income, because it is quite possible for a company or industry, which is generating very large net losses, to have a positive cash flow. In the long run, however, net income is the best measure of resources generated from operations.

Accumulated investment is expressed by (1) total assets, (2) net property, plant, and equipment (PP&E), (3) investment and advances to unconsolidated affiliates, and (4) net investment in place.

Total assets is used in the context of the consolidated company figures, and is the total of the left-hand, or asset side, of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates is of interest because many energy companies extend the range of their activities through subsidiaries which are less than 50-percent owned.

Finally, net investment in place is the total of: (1) net PP&E, and (2) investments and advances to unconsolidated affiliates.

Annual new investment is the measure of newly committed resources during any given year. In the FRS system, this is expressed in terms of: (1) additions to PP&E; (2) current capitalized exploration and development (E&D) expenditures; (3) current expenditures on E&D; (4) additions to investment in unconsolidated affiliates; and (5) additions to net investment in place. The key words are: current, which means simply the cash expended; and capitalized, which refers to the portion of total annual expenditures which are classified as an addition to the PP&E account in the balance sheet instead of being classified as an expense of the current year in the income statement. Being capitalized usually implies that the expenditure benefits future years and will be amortized to expense in the years benefitted. Being expensed implies the benefit is to the current year and, therefore, the item should be shown as an expense of generating that year's revenues. The capitalization concept is at the heart of the difference between the successful efforts versus full cost accounting methods (discussed in the Accounting Practices section of this appendix.) Therefore, in the FRS system, total expenditures that are both expensed and capitalized are used as a measure of activity in order to obviate the effect of differing accounting methods in the context of measuring the deployment of new resources.

Reserve Interests (Foreign)

This category includes all three categories of foreign reserves collected on the FRS form: (1) net ownership interest reserve; (2) proportionate interest in investee reserves and (3) foreign access reserves. These three foreign categories are added together for purposes of comparison with U.S. net working interest reserves because of the different nature of company interests in foreign production as compared to U.S. production.

Foreign petroleum reserve statistics are not strictly comparable to U.S. petroleum reserves because of the more complex and varying arrangements whereby companies obtain foreign crude. In addition, such arrangements have been known to be changed suddenly by those governments, thereby imposing a degree of uncertainty about what a reporting company can describe as their equity reserves. Foreign reserve statistics may be used as an indicator of the rate and magnitude of industry activity, but their different character from U.S. reserves must be recognized.

Accounting Practices

Relation of FRS to Generally Accepted Accounting Principles

In completing the FRS form, with one exception noted below, companies use the same generally accepted accounting principles that they use in their financial statements filed with the SEC and in their annual reports to shareholders. Therefore, the amount and timing of income recognized and the capitalization policies will be the same, and net income in the FRS system will agree in total with that reported in each company's public financial statements.

However, in the FRS system the presentation of the details of financial and statistical data will usually differ somewhat from that presented by most individual companies because current reporting standards do not require standardized functional line of business segments with standardize financial statement line items. In the FRS system, such standardization is necessary because of the need to aggregate a large number of companies (see Sec. 205(h), P.L. 95-91).

FRS Petroleum Supply and Trading Function

In establishing the FRS functional lines of business for reporting the activities of vertically integrated enterprises, it was necessary to define a set of trading rules. The rules define which segment can sell what to whom. Otherwise, the segment data would be inconsistent across companies.

FRS defines the following segments within petroleum. (These segments are the main components of the 5200 series schedules.)

- U.S. Production
- U.S. Refining/Marketing
- Rate-Regulated Pipelines
- Foreign Production
- Foreign Refining/Marketing
- International Marine (Transportation)

A few of the more noteworthy rules, intended to make the trading patterns of each FRS reporting company comparable to those of the other companies, are as follows:

1. Transfers (sales) between segments of the same company are recorded at the equivalent of arm's-length market prices. Where there are no comparable arm's-length transactions, field posted prices may be used. If third party realizations for specific raw material streams are below posted prices, the same lower prices should be used to value internal movements of those raw materials.
2. All crude produced is recorded as a sale by the respective foreign or U.S. production segments to the corresponding foreign or U.S. refining/marketing segments. The production segments are not permitted to sell crude directly to third parties but instead transfer it to the company's refining/marketing segments which then make the sale to the third parties. Companies that do not have foreign refining and import all foreign purchase may deviate from this practice and sell directly to U.S. refining/marketing.
3. Crude purchase from third parties is reflected as a purchase by the appropriate refining/marketing segment: foreign refining/marketing for foreign source crude and U.S. refining/marketing for U.S. source crude. Foreign source crude destined for a U.S. refining segment is then recorded as a

sale by the foreign refining/marketing segment to the U.S. refining/marketing segment.

4. Although production segments are neither sellers to, nor purchasers of, crude from third parties, by FRS system convention, natural gas may be both purchased and sold by production segments.
5. All transportation costs are incurred by the purchasing segment. Therefore, when U.S. refining/marketing purchases crude from foreign refining/marketing, the U.S. refining/marketing segment incurs the cost of transport.
6. With regard to sales to third parties, an export sale is a sale shipped free on board (f.o.b.) destination to a foreign location. In contrast, if a sale is made f.o.b. to a U.S. location, it is considered a U.S. sale even though the goods may ultimately be shipped overseas by a third party who purchased the goods.
7. A U.S. purchase is a purchase made from U.S. sources, even though in the case of goods purchased from U.S. third parties the materials purchased may be of foreign origin. Such purchases are designated as United States purchases in the FRS system because the point of purchase and not the country of production is the determining factor.

Nontraceables and Eliminations

One of the objectives of the FRS system is to allow economic and financial analysis of the energy industry to be performed, as much as possible, by function. These functions, referred to in the FRS as system "segments," are intended for presentation as separate entities with their own income statements. They will reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are, in actual fact, not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments. The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The second is the eliminations classification, which is necessary to prevent double counting of intersegment transactions when the segments are consolidated into total company figures.

The purpose of the nontraceable classification is to capture assets, liabilities, revenues, and expense items, etc., which exist only in the corporate context and cannot reasonably be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm and financial transactions which represent corporate level activities. It should be noted that the financial transactions may play a key role in the firm's ability to do business, but because of their nature, such transactions are not allocated to activities in a single segment. The cash and investment accounts in the balance sheet, and the interest income and expense accounts in the income statement, are the best examples of this. The accompanying example illustrates a nontraceable item, interest expense of $20, and the $10 corresponding tax effect (see "FRS Segment Tax Allocation Rules" in this appendix for further explanation).

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which in turn sells the product again. In the accompanying example, $80 of crude is sold by the U.S. production segment of a petroleum company to the U.S. refining/marketing segment of the same company. The refining/marketing segment records $80 of purchases of crude and, after processing, reflects sales of $160 of refined product. If the segment figures were simply added to arrive at the consolidated total, the consolidated sales figure of $240 ($80 + $160) would be too high because of double counting. Thus, the eliminations classification is created to subtract $80 of sales and $80 of costs, leaving consolidated sales of $160, the appropriate measure of the firm's consolidated transactions.

The nontraceables and eliminations classifications are treated like "pseudo" segments for purposes of aggregating segment data to the consolidated level.

Example of Nontraceables and Eliminations:

Financial Items	Consolidated	Elimination	Nontraceable	Refining/ Marketing	Production
Revenues	160	(80)	--	160	80
Less Expenses:					
General and Administrative	10	--	2	5	3
Other Operations	10	--	--	5	5
Crude	--	(80)	--	80	--
Operating Income	140	--	(2)	70	72
Less Interest Expense	20	--	20	--	--
Less Income Taxes	60	--	(11)	35	36
Net Income	60	--	(11)	35	36

Note: Numbers in parentheses are negative.

FRS Income Taxes

FRS Segment Tax Allocation Rules

In the FRS system, the tax allocated to each segment reflects a pro-rata share of consolidated income taxes. Where the consolidated company has income and pays a tax, but an individual segment has a loss, the segment with a loss reflects a tax benefit. This treatment is an FRS rule and its purpose is to reflect at the segment level the effect of the segment's operations on the consolidated income taxes reported in the company's annual report. The tax benefit reflected at the segment level is limited to that which the consolidated group can use to offset taxes in other segments. In effect, tax benefits at the segment level are recorded only to the extent that they offset taxes in other segments on a consolidated basis.

In comparing an FRS company's segment to a specialized (nonintegrated) company in the same line of business, one must keep the above described rule in mind. The tax effect will be different, for a specialized company cannot report tax benefits for operating losses in the same year. It must carry the loss forward, or backward, against profits of other years, while a segment of an otherwise profitable consolidated firm can show a tax benefit by FRS conventions since a segment's loss can offset profits in other segments on a consolidated basis.

FRS Reporting Companies, Segments, and Tax Paying Entities

This section explains how FRS reporting companies and their individual line-of-business segments differ from the entities which actually pay income taxes. The FRS system is designed to report energy activities on a consolidated company basis, disaggregated into various energy lines of business. Accordingly, income tax expense, current and deferred, is reflected on a line-of-business basis. However, under the tax laws, taxes are not necessarily based upon FRS reporting company consolidated earnings, of the FRS line-of-business segments.

The tax-paying entities of an FRS reporting company are its subsidiaries. Some are incorporated in the United States and some in foreign countries, and each may operate in the United States, foreign countries, or both. Income tax expense in the FRS system consists of both domestic and foreign income taxes incurred by these subsidiaries. Taxes reflected by the consolidated company and each individual segment are allocated from taxes paid and deferred by the actual tax-paying entities.

Under U.S. tax law, U.S. income taxes are not required to be paid by foreign corporations on their foreign operations. Only earnings of foreign corporations earned in the United States or paid into the United States as dividends to the U.S. parent corporation (owner) are taxed by the United States. Foreign and U.S. earnings of U.S. corporations, including divisions and branch operations, are taxed by the United States. All income subject to U.S. tax, whether the entity is a foreign or U.S. corporation, is given the benefit of the foreign income tax credit (up to the statutory rate) to avoid double taxation. Each U.S. incorporated subsidiary of a U.S. corporation elects either to be included in a consolidated U.S. tax return or to file a separate return, depending on which election is most likely to minimize the aggregate U.S. and foreign taxes. The main point to be made here is that corporate organization and relationships are not purely a function of line-of-business financial reporting. This fact requires that allocations be made of taxes incurred so that they can be classified according to the FRS segment format. These allocations are required when a subsidiary is involved in both U.S. and foreign operations and/or in more that one line of energy business. For example, the FRS system has separate segments for the foreign and U.S. petroleum production business, as it also does for the foreign and U.S. refining/marketing business. Therefore, if an FRS reporting company has a foreign subsidiary involved in both petroleum production and refining/marketing of petroleum, a disaggregation of that subsidiary's activities, including income taxes, must be performed.

The disaggregation is further complicated by the existence of nontraceable items such as interest. In making the tax allocation, the nontraceable column must be treated as a line-of-business segment. Therefore, interest expense, which is quite large for most companies, is classified in the nontraceable columns and, accordingly, should generate negative U.S. and foreign income taxes for the nontraceable segment.

In conclusion, an understanding of how taxes affect the operations of a particular line of business cannot be obtained simply by looking at the tax expense associated with an FRS segment. An indepth study of taxation of a line of business must consider the various available forms of corporate organization (the taxpaying entities) and the method of financing (interest expense).

Deferred Taxes

In December 1987, the Financial Accounting Standards Board (FASB) adopted Statement No. 96, *Accounting for Income Taxes.* This statement substantially changes the principles of income tax accounting and is oriented to deferred taxes. FASB currently requires that the new standard be implemented for all fiscal years beginning on or after December 15, 1991. Earlier implementation is encouraged and restatement of earlier financial statements is allowed. Since fewer than half of the FRS companies adopted the new statement through 1989, the following discussion is based on the old standard.

Under GAAP, there must be a matching of revenues with associated expense in the appropriate year. A firm's income statement, including pretax income, is calculated using GAAP. A firm's tax return, and hence income for tax return purposes (taxable income), is calculated based on the tax laws. The differences between GAAP and the tax laws regarding what and where to recognize income and expenses leads to one figure for taxable income and another for GAAP income. The difference may be broken down into: (1) timing differences and (2) permanent differences. Deferred taxes are provided in the financial statements to compensate for the timing differences. This is described more fully below.

An example of a timing difference is depreciation. Under GAAP the straight line method is often used for financial statement purposes, whereas for tax return purposes, an accelerated rate method is permitted. Under accelerated rates, more tax depreciation expense is taken in earlier years of a asset's life than under the GAAP straight line method. Hence, taxable income will be less than GAAP pretax income. The opposite relationship will be true during the final years of the asset's life, and hence, the timing difference "turns around."

In the earlier years in the above example, a pretax GAAP income will be greater than taxable income; therefore, GAAP tax expense will be greater than that reflected on the actual tax returns. The difference between GAAP and tax return tax expense is added to the balance sheet as a "deferred" tax liability. In the later years, assuming all other factors of income tax are constant, pretax GAAP tax expense will be less than that reflected on the actual returns. The difference between GAAP and tax return tax expense is subtracted from the "deferred" tax liability on the balance sheet. At the end of the asset's life, total GAAP and tax return tax expense will be equal.

Reflecting Ownership in Aramco

In 1980, the government of Saudi Arabia acquired a beneficial interest in substantially all of the assets and operations of Aramco. Aramco continues to have access to a significant volume of Saudi Arabian crude oil. As a consequence, the former Aramco partners no longer have a proportional ownership interest in Aramco reserves, but still maintain access to Saudi crude production through marketing agreements.

Prior to 1980, the equity method was used by all four of the Aramco partners (FRS reporting companies) in presenting their interest in the financial statements included in their annual reports to shareholders, although the details of the presentation differ somewhat from company to company. In the 1978 issue of *Performance Profiles,* the equity in Aramco earnings was reflected as a reduction in the cost of crude acquired by the foreign refining/marketing segment. This had the effect of offsetting each company's Aramco earnings against their cost of crude acquired from Aramco at the prevailing purchase price.

In the 1979 issue of *Performance Profiles,* Aramco was reflected in the FRS system on the equity method. That is, the investment and earnings from Aramco were reported on a one-line basis. Prior years were restated to this basis. Likewise, purchases of crude oil, production of crude oil, and interests in reserves were all reflected under the "unconsolidated affiliate" captions.

Corporate Acquisitions

The key topics in the section are: (1) the accounting for mergers -- purchase method versus pooling of interest method; (2) the portion of new investment attributable to transactions between FRS reporting companies; and (3) accounting for internal growth versus growth by acquisition.

Under FRS reporting rules, no acquisitions are accounted for under the pooling of interest method. This is because under the pooling method, the financial statements do not reflect such transactions as new investment, since the historical financial statements are restated. One of the objectives of the FRS is to track new investment activities.

For FRS reporting purposes, acquisitions accounted for as pooling for annual report purposes must be reflected in the FRS filing under a modified purchase method. All purchase accounting rules are followed, except that the assets of the acquired company are not revalued, but are recorded at their book values as stated on the acquired company's books.

Therefore, the FRS balance sheet at year's end will agree with the reporting company's annual report, but the income statement will not. Activities of the acquired company are only reflected in the consolidated financial statements of the acquiring company for the period of time it is owned. Also, the balance sheet accounts of the acquiring company as of the date of acquisition appear in the appropriate captions of the acquiring company's funds statement as sources and uses of funds, or working capital.

The growth of FRS reporting companies, like other industry enterprises, is brought about by management both internally and through the acquisition of other enterprises and individual properties. The FRS schedules at this time do not attempt to distinguish growth through acquisition and merger from internal growth. New investment of funds are classified by line of business and functionally within each line of business. For example all additional investment in producing petroleum properties are classified together, and are not separated according to whether a going corporation came with them or whether only the property was purchased.

Full Cost and Successful Efforts Accounting Methods

At this time, petroleum producing companies reporting to the SEC, which include all FRS reporting companies, are permitted to choose between two accounting methods -- "full cost" and "successful efforts." The two methods differ from one another in the treatment of the cost of dry exploratory holes.

Under full cost, the cost of a dry exploratory hole is capitalized and then amortized to the income statement over the production life of successful wells, which is to say it is spread over may future years. Thus, the capitalized costs of both dry and successful wells are reflected in the balance sheet as part of producing properties.

Under successful efforts, the cost of a dry exploratory hole is written off to expense in the year drilling is determined to be unsuccessful. There is then no capitalized cost of such dry exploratory holes carried on the balance sheet.

In comparison to the successful efforts method, the full cost method will: (1) show less volatility of earnings, since the cost of unsuccessful wells is amortized over many years; (2) show a higher balance in accumulated property, plant, and equipment (PP&E), since the account contains the costs of all wells drilled, including dry exploratory wells; (3) usually show higher earnings during years of intense exploratory activity when a number of dry wells are encountered; and (4) show the same cumulative earnings over a long period of years, since eventually all costs will be amortized to the income statement. These effects are minimized if the firm is large, since the exploratory activities of a large firm are usually smaller relative to total production operations than they are in a small production firm.

Usually one cannot determine the precise effect of using one method over the other. However, one large firm switched from full cost to successful efforts in 1975 and restated 1973 and 1974 data to the successful efforts method. Thus, we have available the impact of this conversion on their comparative net income, net PP&E, and return on net PP&E for 1973 and 1974 (see *text table).*

Years	Full Cost	Successful Efforts
1973		
Net Income (dollars)	1,292,400	1,243,300
Net PP&E (dollars)	8,476,700	7,511,300
Net Income/PP&E (percent)	15.25	16.70
1974		
Net Income (dollars)	1,586,400	1,544,700
Net PP&E (dollars)	9,593,300	8,563,500
Net Income/PP&E (percent)	16.54	17.98

Source: Texaco, Inc., 1974 and 1977 Annual Report and Statistical Supplements.

Since all but one of the FRS companies presently uses successful efforts accounting, the incomparability problem does not seem likely to be severe.

Inventory Accounting--LIFO Versus FIFO

The Last In-First Out (LIFO) and the First In-Last Out (FIFO) inventory methods are most often used in the preparation of the financial statements of industrial enterprises.

Under FIFO, the balance sheet valuation of inventory is based upon the most recent prices paid for the physical units on hand at year's end, and the income statement reflects the cost of units sold at the oldest unit cost. In periods of rapidly rising prices, the income statement reflects higher profits than would be reflected if the units sold were priced at current replacement cost or under the LIFO method.

Under LIFO, the balance sheet valuation of inventory is based on the prices paid for the first units of each major type of inventory ever purchased. For example, crude oil could be carried at $3 per barrel, which of course vastly understates the value of the inventory in terms of its replacement cost. The income statement reflects the cost of units sold at the most recent prices paid for the number of units sold. Thus, cost of goods sold reflects nearly a replacement cost amount, and profits are lower than under the FIFO method.

Since either method is permitted under the Federal tax laws, most companies use LIFO for operations subject to U.S. taxation because earnings and hence taxes are lower than by using FIFO. By 1979, most FRS reporting companies were primarily using the LIFO inventory method. Most analysts probably would agree that LIFO is the preferable method, since the income statement is more realistic than with FIFO. However, its disadvantage is that the balance sheet's inventory figure is understated, and hence the stockholder's equity amount is correspondingly understated.

In 1989, one FRS company reported liquidation profits or losses, compared to 6 and 4 in 1988 and 1987, respectively. The 1989 aggregate liquidation profits increased the reporting companies' operating income by $0.1 billion, which represented 0.4 percent of their aggregate operating income. This compares to $0.1 billion in 1988 and $1.0 billion in 1987, which represented 0.1 percent and 0.3 percent of their respective aggregate operating income for those years.

Foreign Currency Translations

In December 1981, the Financial Accounting Standards Board (FASB) issued Statement No. 52, "Foreign Currency Translations," which superseded FASB-8, "Accounting for the Translation of Foreign Currency Transactions and Foreign Currency Financial Statements." FASB-52 covers the translation of the foreign currency financial statements for the purposes of the consolidation, combination, or reporting by the equity method, and the translation of foreign currency transactions. The new statement required that assets, liabilities, and operations of an entity be stated in the currency of the primary economic environment in which the entity operates (termed, the "functional currency"). If a foreign entity has not kept its financial records in the functional currency, remeasurement is required prior to translation. Any gain or loss on remeasurement is recognized in current net income. The assets and liabilities of the foreign entity are translated from its functional currency to the reporting currency at the current rate of exchange.

Under FASB-52, gain or loss on the translation of foreign currency financial statements is shown as a separate component of stockholders' equity, whereas, under FASB-8, all non-monetary balance sheet items were translated at the historical rate of exchange. Thus, the change to FASB-52, which uses the current rate of exchange, had the most significant impact on inventories and fixed assets. With respect to the income statement, FASB-52 requires that only gains or losses from foreign currency transactions be included.

As the text table below indicates, foreign currency translation gains reduced stockholders' equity by 0.3 percent in 1989, and foreign currency transaction gains increased pretax income by 0.4 percent.

Year	Translation Gain/Losses	Stockholders' Equity	Percent of Stockholders' Equity	Transaction Gains/Losses	Pretax Income	Percent of Pretax Income
	(billion dollars)			(billion dollars)		
1982	-1,764	183,933	-1.0	-111	45,157	-0.2
1983	-1,253	192,509	-0.7	35	47,420	0.1
1984	-1,683	176,461	-1.0	-44	47,609	-0.1
1985	993	165,457	0.6	176	43,573	0.4
1986	1,786	164,601	1.1	543	20,564	2.6
1987	3,425	165,458	2.1	176	25,006	0.7
1988	-495	164,832	-0.3	89	34,285	0.3
1989	-465	160,638	-0.3	142	32,281	0.4

Appendix B

Detailed Statistical Tables

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1988 and 1989

Operating Statistics	FRS Companies			U.S. Industry[1]			FRS as a Percent of U.S. Industry	
	1988	1989	Percent Change	1988	1989	Percent Change	1988	1989
Petroleum								
Net Production								
Crude Oil and Natural Gas Liquids (million barrels)	2,102.1	1,911.1	-9.1	3,565.0	3,317.0	-7.0	59.0	57.6
Natural Gas (billion cubic feet)	7,627.3	7,480.7	-1.9	16,670.0	16,983.0	1.9	45.8	44.0
Net Imports								
Crude Oil and Natural Gas Liquids (million barrels)	906.4	834.3	-8.0	2,003.0	2,289.3	14.3	45.3	36.4
Refinery Capacity (thousand barrels per day)	12,281.0	11,489.0	-6.4	16,285.0	16,238.0	-.3	75.4	70.8
Refinery Output[2] (thousand barrels per day)	12,033.0	11,413.0	-5.2	15,426.0	15,654.6	1.5	78.0	72.9
Bituminous Coal and Lignite Production (million tons)	285.3	286.9	.6	950.3	980.7	3.2	30.0	29.3

[1] U.S. area defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.

[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report* (October 1990). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,364.9 million barrels in 1989 and 3,593.4 million barrels in 1988 (see Energy Information Administration, *Petroleum Supply Annual 1989*, Volume 1 (May 1990), p. 2). For dry natural gas production, the official Energy Information Administration U.S. totals are 17,260 billion cubic feet in 1989 and 17,026 billion cubic feet in 1988 (see Energy Information Administration, *Natural Gas Monthly, August 1990* (November 1990), p. 5).

Sources: Industry data - Petroleum net production: Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989 Annual Report*. Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1988 and 1989. Coal production: Energy Information Administration Form EIA-7A, see *Coal Production 1989*, (December 1990).

Table B2. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1983-1989

Operating Statistics	1983	1984	1985	1986	1987	1988	1989
Petroleum							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	2,059.3	2,088.8	2,120.5	2,089.6	2,069.5	2,102.1	1,911.1
U.S. Industry[1]	3,745.0	3,813.0	3,805.0	3,711.0	3,620.0	3,565.0	3,317.0
FRS as a percent of U.S. Industry	55.0	54.8	55.7	56.3	57.2	59.0	57.6
Natural Gas (billion cubic feet)							
FRS companies	7,365.3	7,946.0	7,340.4	7,143.6	7,214.1	7,627.3	7,480.7
U.S. Industry[1]	15,788.0	17,193.0	15,985.0	15,610.0	16,114.0	16,670.0	16,983.0
FRS as a percent of U.S. Industry	46.7	46.2	45.9	45.8	44.8	45.8	44.0
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	818.7	876.2	727.3	871.3	898.9	906.4	834.3
U.S. Industry[1]	1,386.2	1,426.1	1,309.7	1,697.7	1,877.7	2,003.0	2,289.3
FRS as a percent of U.S. Industry	59.1	61.4	55.5	51.3	47.9	45.3	36.4
Refinery Capacity (thousand barrels per day)							
FRS companies	13,014.0	12,771.0	12,614.0	12,526.0	12,462.0	12,281.0	11,489.0
U.S. Industry[1]	16,773.0	16,325.0	16,126.9	16,234.0	16,581.0	16,285.0	16,238.0
FRS as a percent of U.S. Industry	77.6	78.2	78.2	77.2	75.2	75.4	70.8
Refinery Output[2] (thousand barrels per day)							
FRS companies	10,378.0	10,996.0	10,915.0	11,453.0	11,712.0	12,033.0	11,413.0
U.S. Industry[1]	13,694.0	14,270.0	14,190.0	14,927.0	15,085.0	15,426.0	15,654.6
FRS as a percent of U.S. Industry	75.8	77.1	76.9	76.8	77.6	78.0	72.9
Bituminous Coal and Lignite Production (million tons)							
FRS companies	185.2	226.0	230.4	227.6	255.3	285.3	286.9
U.S. Industry[1]	778.0	891.6	878.9	886.0	915.2	950.3	980.7
FRS as a percent of U.S. Industry	23.8	25.3	26.2	25.7	27.9	30.0	29.3

[1] U.S. area defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.

[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report* (October 1990). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,364.9 million barrels in 1989 and 3,593.4 million barrels in 1988 (see Energy Information Administration, *Petroleum Supply Annual 1989*, Volume 1 (May 1990), p. 2). For dry natural gas production, the official Energy Information Administration U.S. totals are 17,260 billion cubic feet in 1989 and 17,026 billion cubic feet in 1988 (see Energy Information Administration, *Natural Gas Monthly, August 1990* (November 1990), p. 5).

Sources: Industry data - Petroleum net production: Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989 Annual Report*. Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1988 and 1989. Coal production: Energy Information Administration Form EIA-7A, see *Coal Production 1989* (December 1990).

Table B3. A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1989 and Percent Change from 1988

Selected Financial Items	FRS Companies		S&P 400	
	1989 (billion dollars)	Percent Change from 1988	1989 (billion dollars)	Percent Change from 1988
Income Statement				
Operating Revenues	433.6	3.3	2,350.1	5.0
Operating Expenses	-397.7	4.2	-2,107.8	5.0
Operating Income	35.9	-6.1	242.3	4.8
Other Income[1]	-3.1	29.5	-50.8	47.4
Income Taxes	-13.0	-3.6	.0	1.0
Net Income	19.8	-11.4	122.9	-4.5
Cash Flows from Operations[2]				
Net Income	19.8	-11.4	122.9	-4.5
Other Items, Net[3]	28.5	9.2	86.5	-3.1
Net Cash Flow from Operations	48.3	-.3	209.3	-3.9
Cash Flows from Investing Activities[2]				
Additions to PP&E	-43.5	-12.6	-163.1	8.3
Other Investment Activities, Net[4]	9.7	-53.0	-51.5	6.9
Net Cash Flow from Investing Activities	-33.8	16.2	-214.6	8.0
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	20.7	7.0	204.6	31.7
Proceeds from Equity Security Offerings	4.2	56.8	19.0	76.4
Dividends to Shareholders	-16.7	34.2	-55.8	4.8
Reductions in Long-Term Debt	-19.8	-31.1	-158.3	26.6
Stock Repurchases	-6.2	-6.7	-34.9	4.4
Other Financing Activities, Net	2.1	411.1	21.5	-23.2
Net Cash Flow from Financing Activities	-15.7	-38.3	-3.9	-78.1
Effect of Exchange Rate Changes on Cash	-.3	15.8	-1.3	76.3
Increase (Decrease) in Cash and Cash Equivalents	-1.5	(5)	-11.7	(5)

[1] 'Other Income' includes other revenue and expense, discontinued operations, extraordinary items, and accounting changes.

[2] Items that add to cash are positive, and items that use cash are shown as negative values.

[3] 'Other Items, Net' includes: DD&A, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of PP&E, changes in operating assets and liabilities, and other noncash items, excluding net change in short-term debt; other cash items, net.

[4] 'Other Investment Activities, Net' includes additions to investments and advances and proceeds from disposals of PP&E.

[5] Not meaningful.

Sources: S&P 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B4. Consolidating Statement of Income for FRS Companies, 1989
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Non-Traceable	Petroleum	Coal	Nuclear & Other Energy	Non-Energy
Operating Revenues	433,609	-12,031	343,398	6,861	1,054	94,327
Operating Expenses						
General Operating Expenses	358,387	-10,669	288,096	5,273	981	74,706
DD&A	29,598	591	24,056	630	151	4,170
General & Administrative	9,741	832	5,954	180	75	2,700
Total Operating Expenses	397,726	-9,246	318,106	6,083	1,207	81,576
Operating Income	35,883	-2,785	25,292	778	-153	12,751
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	2,774	172	2,118	W	W	438
Other Dividend & Interest Income	2,676	2,676	-	-	-	-
Gain/Loss on Disposition of PP&E	1,323	-147	990	W	W	470
Interest Expenses & Financial Charges	-11,523	-11,523	-	-	-	-
Minority Interest in Income	-424	-424	-	-	-	-
Foreign Currency Translation Effects	142	142	-	-	-	-
Other Revenue & (Expense)	1,430	1,430	-	-	-	-
Total Other Revenue & (Expense)	-3,602	-7,674	3,108	50	6	908
Pretax Income	32,281	-10,459	28,400	828	-147	13,659
Income Tax Expense	13,013	-3,993	12,122	215	-47	4,716
Discontinued Operations	233	W	W	W	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	283	W	W	W	W	W
Net Income	19,784	-5,531	16,207	441	-70	8,737

- = Not available.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B5. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1989
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	Intl Marine
Operating Revenues								
Raw Material Sales	69,927	45,901	58,424	W	49,063	28,863	41,399	0
Refined Products Sales	122,739	W	121,929	W	97,851	W	98,051	W
Transportation Revenues	7,841	146	1,884	8,498	1,522	142	W	2,170
Management And Processing Fees	1,121	407	791	W	988	W	W	0
Other	7,595	1,266	6,481	277	2,971	634	2,369	W
Total Operating Revenues	209,223	47,736	189,509	10,157	152,395	30,045	142,919	2,208
Operating Expenses								
General Operating Expenses	174,251	27,125	178,923	6,405	132,064	14,152	138,711	1,957
DD&A	17,388	13,580	2,883	925	6,668	5,430	1,128	110
General & Administrative	4,056	1,821	1,962	274	1,899	852	1,047	21
Total Operating Expenses	195,695	42,526	183,768	7,604	140,631	20,434	140,886	2,088
Operating Income	13,528	5,210	5,741	2,553	11,764	9,611	2,033	120
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	531	26	229	276	1,587	1,080	W	W
Gain(Loss) On Disposition of PP&E	386	35	334	17	604	137	W	W
Total Other Revenue & (Expense)	917	61	563	293	2,191	1,217	856	118
Pretax Income	14,445	5,271	6,304	2,846	13,955	10,828	2,889	238
Income Tax Expense	4,912	2,220	1,746	942	7,210	6,079	1,073	20
Discontinued Operations	W	0	W	0	W	W	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	W	0	W	0	W	W	0	0
Contribution To Net Income	9,497	3,051	4,522	1,904	6,710	4,714	1,816	218

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B6. Profit Rates for Lines of Business and Petroleum Segments for FRS Companies, 1983-1989
(Percent)

Line of Business	1983	1984	1985	1986	1987	1988	1989
Consolidated	7.4	6.9	5.5	3.0	3.6	7.2	6.4
Petroleum	11.3	10.4	10.5	5.5	6.2	7.3	6.7
U.S. Petroleum	10.3	9.4	9.4	3.0	4.9	6.3	5.8
Oil and Gas Production	11.3	10.8	9.5	.8	4.1	2.8	2.9
Refining/Marketing	4.8	.3	6.5	4.5	2.9	14.7	11.5
Pipelines	16.6	20.8	15.0	13.2	12.8	9.6	10.2
Foreign Petroleum	14.1	13.3	13.8	12.8	9.5	9.9	8.7
Oil and Gas Production	19.6	18.8	20.0	11.6	12.4	9.2	8.9
Refining/Marketing	7.7	4.5	3.3	16.3	4.7	11.6	8.0
International Marine	-13.2	-14.0	-19.0	5.3	-3.6	6.8	12.4
Coal	5.0	6.2	4.6	2.7	5.1	6.7	5.0
Nuclear and Other Energy	.5	-1.8	-8.4	-.8	.5	-2.5	-2.3
Nonenergy	2.9	4.8	4.2	5.1	12.2	20.3	17.3

Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28.

Table B7. Profit Rates for Petroleum Segments for FRS Companies Ranked by Total Ene:gy Assets, 1987-1989

(Percent)

Petroleum Segments	Top Four			Five Through Twelve			All Other		
	1987	1988	1989	1987	1988	1989	1987	1988	1989
Petroleum	6.6	8.3	6.1	6.1	5.6	7.1	5.3	9.4	7.9
U.S. Petroleum	3.6	5.2	2.9	5.9	5.7	7.1	4.8	10.3	8.6
Oil and Gas Production	4.0	.9	2.2	4.1	2.1	2.6	4.6	12.5	5.9
Refining/Marketing	-1.0	14.8	1.6	8.0	15.8	20.2	.7	11.9	12.7
Pipelines	22.7	23.4	20.0	12.6	9.4	8.0	9.5	4.4	9.6
Foreign Petroleum	10.4	12.6	9.7	6.8	5.0	7.1	8.2	4.1	4.5
Oil and Gas Production	16.5	13.5	11.8	5.3	4.2	5.4	8.5	4.4	4.4
Refining/Marketing	3.5	11.9	7.2	30.3	12.6	20.2	6.0	1.2	5.8
International Marine	-5.4	5.6	6.6	4.6	10.7	54.7	10.3	75.0	0

Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28.

Table B8. A Comparison of Balance Sheet Items for FRS Companies and the S&P 400, 1989 and Percent Change from 1988

Balance Sheet Items	FRS Companies		S&P 400	
	1989 (billion dollars)	Percent Change from 1988	1989 (billion dollars)	Percent Change from 1988
Assets				
Current Assets	102.4	-2.4	608.8	2.9
Noncurrent Assets				
Property, Plant, and Equipment				
Gross	536.0	1.8	1,515.6	5.7
Accumulated DD&A	-242.8	4.2	-668.8	6.2
Net	293.2	-.1	846.8	5.4
Investments and Advances	16.7	4.6	59.1	12.1
Other Noncurrent Assets	22.2	-4.1	942.0	14.4
Subtotal Noncurrent Assets	332.1	-.2	1,848.0	10.0
Total Assets	434.5	-.7	2,456.8	8.1
Liabilities and Stockholders' Equity				
Liabilities				
Current Liabilities	99.0	4.8	532.0	10.4
Long-Term Debt	90.7	-2.8	533.4	11.1
Other Long-Term Items	80.0	-2.0	576.5	8.6
Minority Interest	4.2	18.8	18.2	27.3
Subtotal Liabilities and Other Items	273.9	.4	1,660.3	10.1
Stockholders' Equity				
Retained Earnings	140.9	-2.0	664.0	3.5
Other Equity	19.7	-6.2	132.4	7.7
Subtotal Stockholders' Equity	160.6	-2.5	796.5	4.2
Total Liabilities and Stockholders' Equity	434.5	-.7	2,456.8	8.1

Sources: S&P 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B9. Consolidated Balance Sheet for FRS Companies, 1983-1989
(Billion Dollars)

Balance Sheet Items	1983	1984	1985	1986	1987	1988	1989
Assets							
Current Assets							
Cash & Marketable Securities	22.9	18.2	17.8	25.2	25.7	16.8	16.4
Trade Accounts and Notes Receivable	44.8	38.0	44.5	34.9	40.2	43.7	45.4
Inventories							
Raw Materials & Products	25.9	26.0	28.6	26.7	29.1	26.9	26.2
Materials & Supplies	7.4	6.5	6.2	5.5	5.6	5.3	5.3
Other Current Assets	10.2	12.2	12.5	11.1	8.8	12.2	9.2
Total Current Assets	111.2	101.0	109.6	103.3	109.4	105.0	102.4
Non-current Assets							
Property, Plant & Equipment							
Gross	440.2	453.4	478.4	495.2	525.5	526.7	536.0
Accumulated DD&A	161.8	161.0	180.7	204.1	227.9	233.0	242.8
Net	278.4	292.4	297.7	291.1	297.6	293.6	293.2
Investment & Advances to Unconsolidated Affiliates	17.9	17.0	17.7	18.9	18.8	16.0	16.7
Other Non-current Assets	14.2	12.6	13.4	13.8	17.9	23.2	22.2
Total Non-current Assets	310.5	322.0	328.8	323.7	334.2	332.8	332.1
Total Assets	421.8	422.9	438.4	427.0	443.6	437.8	434.5
Liabilities & Stockholder's Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	50.9	49.3	58.1	42.5	48.3	45.9	51.9
Other Current Liabilities	40.1	41.7	49.2	46.5	49.6	48.5	47.1
Long Term Debt	67.1	87.3	89.9	92.1	95.3	93.2	90.7
Deferred Income Tax Credits	43.2	42.4	48.2	49.2	51.1	50.4	49.8
Other Deferred Credits	8.3	8.0	9.9	10.7	10.8	11.8	10.9
Other Long Term Items	16.7	15.7	17.0	18.7	19.7	19.4	19.3
Minority Interest in Consolidated Affiliates	3.0	2.2	2.7	2.9	3.4	3.6	4.2
Total Liabilities	229.3	246.5	272.9	262.4	278.2	272.9	273.9
Stockholders' Equity							
Retained Earnings	161.4	154.6	150.1	144.8	143.2	143.8	140.9
Other Equity	31.1	21.9	15.4	19.8	22.2	21.0	19.7
Total Stockholders' Equity	192.5	176.5	165.5	164.6	165.5	164.8	160.6
Total Liabilities & Stockholders' Equity	421.8	422.9	438.4	427.0	443.6	437.8	434.5
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	.0	-4.4	-3.3	-2.2	-4.0	-4.7	-4.3
Foreign Currency Translation Adjustment for the Current Year	.0	-1.7	1.0	1.8	3.4	-.5	-.5

Source: Energy Information Administration, Form EIA-28.

Table B10. Distribution of Net Investment in Place for FRS Companies, United States and Foreign, 1989

Fixed Investment	Consolidated Company	United States	Foreign	Nontraceable[1]
Net Investment in Place (billion dollars)				
Net Property, Plant, and Equipment	293.2	207.5	80.1	5.6
Investment and Advances to Unconsolidated Affiliates	16.7	4.6	11.5	.6
Total Net Investment in Place	309.9	212.1	91.6	6.2
Net Investment in Place (percent distribution)				
Net Property, Plant, and Equipment	100.0	70.8	27.3	1.9
Investment and Advances to Unconsolidated Affiliates	100.0	27.5	68.9	3.6
Total Net Investment in Place	100.0	68.4	29.5	2.0
Additions to Investment in Place (billion dollars)				
Property, Plant, and Equipment	43.5	25.4	17.3	.8
Investment and Advances to Unconsolidated Affiliates	1.5	.7	.8	.1
Total Additions to Investment in Place	45.0	26.0	18.1	.9
Additions to Investment in Place (percent distribution)				
Property, Plant, and Equipment	100.0	58.3	39.8	1.9
Investment and Advances to Unconsolidated Affiliates	100.0	45.2	51.4	3.4
Total Additions to Investment in Place	100.0	57.9	40.2	1.9

[1] Includes items in consolidated balance sheet that cannot be allocated to segments (nontraceables). In this table, this column is derived as a residual.

[2] Not meaningful.

Source: Energy Information Administration, Form EIA-28.

Table B11. Net Property, Plant, and Equipment (PP&E), Additions to PP&E, Investments and Advances, and Depreciation, Depletion and Amortization (DD&A), by Lines of Business for FRS Companies, 1989

(Million Dollars)

Line of Business	Year End Balance		Activity During Year		
	Net PP&E	Investments and Advances	Additions to PP&E	Additions to Investments and Advances	DD&A
Nonenergy					
Foreign Chemicals	5,645	2,211	1,258	40	551
U.S. Chemicals	22,889	634	4,755	260	2,511
Foreign Other Nonenergy	2,859	374	265	-6	182
U.S. Other Nonenergy	14,935	964	1,965	220	926
Total Nonenergy	46,328	4,183	8,243	514	4,170
Nuclear and Other Energy					
Foreign	1,404	0	91	0	66
United States	1,679	7	82	-14	85
Total Nuclear and Other Energy	3,083	7	173	-14	151
Coal					
Foreign	1,737	W	410	W	W
United States	6,538	W	553	W	W
Total Coal	8,275	470	963	85	630
Petroleum					
United States					
Production	105,643	310	11,892	32	13,580
Refining/Marketing					
Refining	20,219	818	2,344	78	1,670
Marketing	13,947	236	2,804	W	901
Refining/Marketing Transport					
Pipelines	1,242	289	109	38	94
Marine	2,075	W	37	W	155
Other	541	W	124	W	63
Total U.S. Refining/Marketing	38,024	1,385	5,418	121	2,883
Rate Regulated Pipelines					
Refined Products	1,081	206	88	W	58
Natural Gas	9,933	269	443	W	374
Crude Oil and Liquids	6,779	452	169	23	493
Total Rate Regulated Pipelines	17,793	927	700	20	925
Total U.S. Petroleum	161,460	2,622	18,010	173	17,388
Foreign					
Production	49,693	3,049	11,430	957	5,430
Refining/Marketing	16,994	5,723	3,655	-299	1,128
International Marine	1,738	21	225	2	110
Total Foreign Petroleum	68,425	8,793	15,310	660	6,668
Total Petroleum	229,885	11,415	33,320	833	24,056
Nontraceable	5,642	607	824	50	591
Consolidated	293,213	16,682	43,523	1,468	29,598

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B12. Income and Investment Patterns in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1989 and Percent Change from 1988

Income and Investment	Worldwide	United States	Foreign
		(million dollars)	
1989			
Contribution to Net Income			
Top Four	6,814.0	1,737.0	5,077.0
Five Through Twelve	6,907.0	5,517.0	1,390.0
All Other	2,486.0	2,243.0	243.0
Net Investment in Place[1]			
Top Four	111,945.0	59,789.0	52,156.0
Five Through Twelve	97,930.0	78,218.0	19,712.0
All Other	31,425.0	26,075.0	5,350.0
Additions to Investment in Place			
Top Four	17,843.0	6,248.0	11,595.0
Five Through Twelve	10,510.0	7,537.0	2,973.0
All Other	5,800.0	4,398.0	1,402.0
		(percent)	
Distribution, 1989			
Contribution to Net Income			
Top Four	100.0	25.5	74.5
Five Through Twelve	100.0	79.9	20.1
All Other	100.0	90.2	9.8
Net Investment in Place[1]			
Top Four	100.0	53.4	46.6
Five Through Twelve	100.0	79.9	20.1
All Other	100.0	83.0	17.0
Additions to Investment in Place			
Top Four	100.0	35.0	65.0
Five Through Twelve	100.0	71.7	28.3
All Other	100.0	75.8	24.2
Change from 1988			
Contribution to Net Income			
Top Four	-23.6	-45.6	-11.3
Five Through Twelve	22.7	18.4	43.3
All Other	-15.0	-17.7	23.4
Net Investment in Place[1]			
Top Four	4.8	-2.5	14.7
Five Through Twelve	-2.5	-3.5	1.9
All Other	.8	-1.2	12.2
Additions to Investment in Place			
Top Four	18.7	-35.0	114.0
Five Through Twelve	-41.4	-29.2	-59.2
All Other	-4.7	-12.8	34.7

[1] Measured as net property, plant, and equipment plus investment and advances.

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.

Source: Energy Information Administration, Form EIA-28.

Table B13. Income and Investment Patterns by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1989 and Percent Change from 1988

Income and Investment	United States				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
	(million dollars)							
1989								
Contribution to Net Income								
Top Four	1,737.0	933.0	255.0	537.0	5,077.0	3,548.0	1,465.0	102.0
Five Through Twelve	5,517.0	1,327.0	3,321.0	867.0	1,390.0	963.0	311.0	116.0
All Other	2,243.0	791.0	946.0	500.0	243.0	203.0	40.0	.0
Net Investment in Place[1]								
Top Four	59,789.0	41,620.0	15,486.0	2,683.0	52,156.0	30,129.0	20,482.0	1,545.0
Five Through Twelve	78,218.0	50,903.0	16,464.0	10,851.0	19,712.0	17,960.0	1,540.0	212.0
All Other	26,075.0	13,430.0	7,459.0	5,186.0	5,350.0	4,653.0	695.0	2.0
Additions to PP&E[2]								
Top Four	6,224.0	4,326.0	1,818.0	80.0	10,999.0	7,331.0	3,527.0	141.0
Five Through Twelve	7,477.0	4,822.0	2,378.0	277.0	3,192.0	3,038.0	70.0	84.0
All Other	4,309.0	2,744.0	1,222.0	343.0	1,119.0	1,061.0	58.0	.0
	(percent)							
Distribution, 1989								
Contribution to Net Income								
Top Four	100.0	53.7	14.7	30.9	100.0	69.9	28.9	2.0
Five Through Twelve	100.0	24.1	60.2	15.7	100.0	69.3	22.4	8.3
All Other	100.0	35.3	42.2	22.3	100.0	83.5	16.5	.0
Net Investment in Place[1]								
Top Four	100.0	69.6	25.9	4.5	100.0	57.8	39.3	3.0
Five Through Twelve	100.0	65.1	21.0	13.9	100.0	91.1	7.8	1.1
All Other	100.0	51.5	28.6	19.9	100.0	87.0	13.0	.0
Additions to PP&E[2]								
Top Four	100.0	69.5	29.2	1.3	100.0	66.7	32.1	1.3
Five Through Twelve	100.0	64.5	31.8	3.7	100.0	95.2	2.2	2.6
All Other	100.0	63.7	28.4	8.0	100.0	94.8	5.2	.0
Change from 1988								
Contribution to Net Income								
Top Four	-45.6	130.9	-88.3	-14.8	-11.3	3.2	-33.3	22.9
Five Through Twelve	18.4	15.9	35.4	-18.1	43.3	33.8	40.7	346.2
All Other	-17.7	-51.1	15.9	71.2	23.4	12.8	400.0	-100.0
Net Investment in Place[1]								
Top Four	-2.5	-5.3	5.3	-.3	14.7	18.1	10.8	4.5
Five Through Twelve	-3.5	-6.2	6.2	-3.9	1.9	3.5	-12.0	-12.4
All Other	-1.2	4.1	8.6	-21.8	12.2	14.3	1.2	-83.3
Additions to PP&E[2]								
Top Four	-28.7	-30.3	-23.8	-41.2	120.3	152.2	76.6	27.0
Five Through Twelve	-30.6	-42.2	9.9	6.9	-54.7	-51.0	-91.1	31.3
All Other	-15.3	-18.3	-12.4	2.7	7.6	7.3	23.4	-100.0

[1] Measured as net property, plant, and equipment plus investment and advances.

[2] Property, plant, and equipment.

[3] Not meaningful.

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.

Source: Energy Information Administration, Form EIA-28.

Table B14. Size Distribution of Income and Investment Within Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1987-1989

(Percent)

Patterns Across Size Groups	Worldwide			United States			Foreign		
	1987	1988	1989	1987	1988	1989	1987	1988	1989
Contribution to Net Income									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	48.8	51.0	42.0	26.6	30.2	18.3	78.2	83.1	75.7
Five Through Twelve	38.4	32.2	42.6	56.1	44.0	58.1	15.1	14.1	20.7
All Other	12.7	16.7	15.3	17.3	25.8	23.6	6.7	2.9	3.6
Net Investment in Place[1]									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	45.8	44.8	46.4	35.9	36.3	36.4	71.3	65.4	67.5
Five Through Twelve	39.3	42.1	40.6	46.4	48.0	47.7	21.1	27.8	25.5
All Other	14.9	13.1	13.0	17.7	15.6	15.9	7.7	6.9	6.9
Additions to Investment in Place									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	43.1	38.5	52.2	31.7	38.0	34.4	68.7	39.4	72.6
Five Through Twelve	43.6	45.9	30.8	51.7	42.1	41.5	29.3	53.0	18.6
All Other	13.3	15.6	17.0	16.5	19.9	24.2	7.7	7.6	8.8

[1] Measured as net property, plant, and equipment plus investment and advances.

Source: Energy Information Administration, Form EIA-28.

Table B15. Consolidated Statement of Cash Flows for FRS Companies, 1986-1989

(Million Dollars)

Cash Flows[1]	1986	1987	1988	1989
Cash Flows From Operations				
Net Income	9,167	11,257	22,339	19,784
Minority Interest in Income	398	573	585	424
Noncash Items				
DD&A	31,239	30,673	31,052	29,598
Dry Hole Expense, This Year	3,385	1,780	2,764	2,258
Deferred Income Taxes	3,806	768	1,279	189
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-594	-280	-338	-794
(Gain)/Loss on Disposition of PP&E	-1,573	-1,561	-2,064	-3,335
Changes in Operating Assets and Liabilities and Other Noncash Items	-3,719	1,847	-4,741	809
Other Cash Items, Net	2,085	2,085	-2,449	-649
Net Cash Flow From Operations	44,194	47,142	48,427	48,284
Cash Flows From Investing Activities				
Additions to PP&E:				
Due to Mergers and Acquisitions	-9,857	-5,830	-15,144	-8,676
Other	-27,891	-28,950	-34,653	-34,847
Total Additions to PP&E	-37,748	-34,780	-49,797	-43,523
Additions to Investments and Advances	-1,947	-31	121	-349
Proceeds From Disposals of PP&E	11,202	6,367	15,960	13,217
Other Investment Activities, Net	2,676	-5,347	4,623	-3,141
Cash Flow From Investing Activities	-25,817	-33,791	-29,093	-33,796
Cash Flows From Financing Activities				
Proceeds From Long-Term Debt	30,431	19,748	19,313	20,668
Proceeds From Equity Security Offerings	5,048	2,312	2,709	4,248
Reductions in Long-Term Debt	-30,068	-20,209	-28,775	-19,820
Purchase of Treasury Stock	-2,794	-3,839	-6,637	-6,190
Dividends to Shareholders	-11,319	-10,593	-12,443	-16,699
Other Financing Activities, Including Net Change in Short-Term Debt	-4,568	-2,478	413	2,111
Cash Flow From Financing Activities	-13,270	-15,059	-25,420	-15,682
Effect of Exchange Rate on Cash	127	457	-247	-286
Net Increase/(Decrease) in Cash and Cash Equivalents	5,234	-1,251	-6,333	-1,480

[1] Items that add to cash are positive, and items that use cash are shown as negative values.

Source: Energy Information Administration, Form EIA-28.

Table B16. A Comparison of Key Financial Indicators, Selected Performance Measures, and Patterns of Finance for FRS Companies and for the S&P 400, 1987-1989

(Percent)

Financial Indicators	FRS Companies			S&P 400		
	1987	1988	1989	1987	1988	1989
Profitability Measures						
Net Income to Total Assets	2.5	5.1	4.6	5.6	5.7	5.0
Net Income to Stockholders' Equity	6.8	13.6	12.3	13.6	16.8	15.4
Net Income Plus Interest to Total Invested Capital	8.8	13.4	12.5	13.6	15.8	15.5
Cash Flow from Operations and Uses of Cash						
Net Cash Flow from Operations to Total Assets	10.6	11.1	11.1	–	9.6	8.5
Additions to PP&E to Net Cash Flow from Operations	73.8	102.8	90.1	–	69.1	77.9
Dividends to Net Cash Flow from Operations	22.5	25.7	34.6	–	24.5	26.7
Liquidity and Leverage Measures						
Long-Term Debt to Stockholders' Equity	57.6	56.6	56.4	43.7	62.8	67.0
Long-Term Debt to Total Assets	21.5	21.3	20.9	17.9	21.1	21.7
Current Assets to Current Liabilities	111.7	111.1	103.5	149.2	122.7	114.4

– = Not available.

Sources: S&P 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B17. Worldwide Income Taxes for FRS Companies, 1988 and 1989

Taxes by Geographic Sector	Billion Dollars		Percent Change from 1988	Income Taxes as a Percent of Pretax Income	
	1988	1989		1988	1989
Pretax Income[1]	34.3	32.3	-5.8	100.0	100.0
Income Taxes					
U.S. Federal	5.5	4.1	-25.6	16.0	12.7
U.S. State and Local	.8	1.0	22.6	2.5	3.2
Foreign	7.1	7.9	10.1	20.9	24.4
Total Income Taxes	13.5	13.0	-3.6	39.4	40.3
Current Income Taxes					
U.S. Federal	3.8	4.0	4.9	11.2	12.5
U.S. State and Local	.9	1.1	18.5	2.6	3.3
Foreign					
Canada	.5	.7	39.7	1.5	2.2
OECD Europe	2.8	2.3	-20.4	8.3	7.0
Africa	1.2	1.6	37.8	3.4	5.0
Middle East	.7	1.0	48.8	2.0	3.1
Other Eastern Hemisphere	1.4	1.5	4.4	4.1	4.6
Other Western Hemisphere	.7	.6	-11.4	2.0	1.9
Subtotal	7.3	7.7	5.1	21.3	23.8
Total Current Income Taxes	12.2	12.8	4.7	35.6	39.6
Deferred Income Taxes					
U.S. Federal	1.7	.1	-95.9	4.9	.2
U.S. State and Local	-.1	.0	(2)	-.2	-.1
Foreign	-.2	.2	(2)	-.5	.6
Total Deferred Income Taxes	1.3	.2	-83.0	3.7	.7

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.

[2] Not meaningful.

Source: Energy Information Administration, Form EIA-28.

Table B18. U.S. Federal Income Taxes for FRS Companies, 1988 and 1989

U.S. Tax Determination	Billion Dollars		Percent Change from 1988	Percent of Net Income Before Taxes	
	1988	1989		1988	1989
Pretax Income[1] (worldwide)	34.3	32.3	-5.8	100.0	100.0
Adjustments to Income					
Income Not Subject to U.S. Taxes	-3.8	-4.0	5.4	-11.2	-12.5
Deductions for Income Taxes Paid in Other Jurisdictions	-1.4	-1.7	18.8	-4.1	-5.2
Taxable Income	29.0	26.6	-8.5	84.7	82.3
Expected Tax Computed at U.S. Statutory Rate	9.9	9.0	-8.5	28.8	28.0
Cause of Increase or Decrease in Taxes					
Statutory Depletion	-.1	-.1	2.7	-.3	-.4
Foreign Tax Credits	-4.8	-5.0	5.3	-13.9	-15.5
Alternative Minimum Tax	.0	.0	.0	.0	.0
Investment Tax Credits	-.1	.0	([2])	-.4	-.1
Other	.6	.2	-66.4	1.9	.7
U.S. Federal Income Tax Expense on U.S. Taxable Income	5.5	4.1	-25.4	16.0	12.7
Current	3.8	4.0	4.9	11.2	12.5
Deferred	1.7	.1	-95.9	4.9	.2

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.

[2] Not meaningful.

Source: Energy Information Administration, Form EIA-28.

Table B19. Analysis of Income Taxes for FRS Companies, 1983-1989
(Million Dollars)

Income Taxes	1983	1984	1985	1986	1987	1988	1989
Income Taxes (as per Financial Statements)							
Current Paid or Accrued							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	5,822	4,922	4,385	-526	4,099	4,283	4,071
U.S. Federal Investment Tax Credit	-1,794	-1,416	-1,298	-749	-365	-449	-48
Effect of Alternative Minimum Tax	0	0	0	0	40	174	24
U.S. State & Local Income Taxes	665	753	848	387	694	901	1,068
Foreign Income Taxes							
Canada	1,490	1,894	1,614	654	890	501	700
OECD Europe	5,846	6,241	5,904	2,988	3,083	2,840	2,261
Africa	4,355	4,126	4,312	1,392	1,479	1,176	1,620
Middle East	1,761	1,849	1,690	734	1,099	670	997
Other Eastern Hemisphere	1,518	2,317	1,926	1,204	1,287	1,421	1,483
Other Western Hemisphere	869	780	1,028	628	703	700	620
Total Foreign	15,839	17,208	16,474	7,600	8,541	7,308	7,681
Total Current	20,532	21,467	20,409	6,712	13,009	12,217	12,796
Deferred							
U.S. Federal, before Investment Tax Credit	3,051	4,094	3,696	2,423	474	1,260	45
U.S. Federal Investment Tax Credit	175	-226	-269	201	188	405	23
Effect of Alternative Minimum Tax	0	0	0	0	-31	-173	-13
U.S. State & Local Income Taxes	53	10	-39	137	23	-54	-30
Foreign	1,650	770	1,489	1,046	114	-159	192
Total Deferred	4,929	4,648	4,877	3,806	768	1,279	217
Total Income Tax Expense	25,461	26,115	25,286	10,518	13,777	13,496	13,013
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	47,420	47,609	43,573	20,564	25,006	34,285	32,281
Less: Foreign Source Income not Subject to U.S. Tax	5,525	5,741	5,941	4,768	3,670	3,830	4,036
Equals: Income Subject to U.S. Tax	41,895	41,868	37,632	15,796	21,336	30,455	28,245
Less: U.S. State & Local Income Taxes	718	764	808	617	717	841	1,023
Less: Applicable Foreign Income Taxes Deducted	2,920	2,832	2,088	425	475	578	663
Equals: Pretax Income Subject to U.S. Tax	38,256	38,272	34,736	14,754	20,144	29,036	26,559
Tax Provision Based on Previous Line	17,598	17,605	15,978	6,787	8,145	9,873	9,030
Increase/(Decrease) in Taxes Due To							
Foreign Tax Credits Recognized	-9,003	-9,130	-10,593	-7,046	-5,454	-4,763	-5,014
U.S. Federal Investment Tax Credit Recognized	-1,627	-1,621	-1,485	-618	-177	-145	-26
Statutory Depletion	-278	-260	-151	-130	-115	-111	-114
Effect of Alternative Minimum Tax	0	0	0	0	10	1	10
Other	562	779	2,765	2,355	1,997	642	216
Actual U.S. Federal Tax Provision (Refund)	7,252	7,373	6,514	1,348	4,406	5,497	4,102

Source: Energy Information Administration, Form EIA-28.

Table B20. U.S. Taxes Other Than Income Taxes for FRS Companies, 1989 and Percent Change from 1988

U.S. Taxes Other than Income Taxes	Total United States		Petroleum		Coal		Other[1]	
	1989 (million dollars)	Percent Change from 1988	1989 (million dollars)	Percent Change from 1988	1989 (million dollars)	Percent Change from 1988	1989 (million dollars)	Percent Change from 1988
Production Taxes								
Windfall Profit Tax	-19.0	-88.8	-19.0	-88.8	0.0	—	0.0	—
Severance Taxes	2,291.0	20.7	2,115.0	19.8	W	W	W	W
Other Direct Production Taxes	236.0	-1.7	186.0	-9.3	W	W	W	W
Total Production Taxes	2,508.0	27.4	2,282.0	26.7	201.0	35.8	25.0	31.6
Superfund	240.0	7.1	185.0	7.6	.0	—	55.0	5.8
Import Duties	173.0	-16.0	–	–	–	–	–	–
Sales, Use, and Property	2,555.0	-8.2	–	–	–	–	–	–
Payroll	1,940.0	-6.2	–	–	–	–	–	–
Other Taxes	816.0	13.8	–	–	–	–	–	–
Total Taxes Paid (Other Than Income Taxes)	8,232.0	3.3	–	–	–	–	–	–
Excise Taxes Collected	13,418.0	.2	–	–	–	–	–	–

[1] Nuclear, Other Energy, and Nonenergy.
– = Not available.
W = Data withheld to avoid disclosure.
— = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B21. Petroleum Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1989 and Percent Change from 1988

Exploration and Development Expenditures	Worldwide Expenditures	U.S. Expenditures			Foreign Expenditures		
	FRS Companies (million dollars) 1989	FRS Companies (million dollars) 1989	Percent Change from 1988	United States FRS as a Percent of Total FRS 1989	FRS Companies (million dollars) 1989	Percent Change from 1988	FRS Foreign as a Percent of Total FRS 1989
Exploration							
Acquisition of Unproved Acreage	2,080.0	1,065.0	-54.7	51.2	1,015.0	25.0	48.8
Geological and Geophysical	1,633.0	742.0	-22.1	45.4	891.0	2.5	54.6
Drilling and Equipping[1]	3,589.0	1,876.0	-17.9	52.3	1,713.0	-1.4	47.7
Other	2,150.0	1,224.0	-15.6	56.9	926.0	14.7	43.1
Total Exploration	9,452.0	4,907.0	-30.3	51.9	4,545.0	7.5	48.1
Development							
Acquisition of Proved Acreage	5,398.0	2,170.0	-57.0	40.2	3,228.0	-7.9	59.8
Lease Equipment	4,242.0	2,029.0	.3	47.8	2,213.0	33.6	52.2
Drilling and Equipping[1]	6,826.0	3,840.0	1.4	56.3	2,986.0	16.4	43.7
Other[2]	3,199.0	2,043.0	-34.4	63.9	1,156.0	6.3	36.1
Total Development	19,665.0	10,082.0	-27.8	51.3	9,583.0	8.7	48.7
Total Exploration and Development	29,117.0	14,989.0	-28.7	51.5	14,128.0	8.3	48.5

[1] Expenditure incurred in a given year not cumulative (includes work in progress adjustment).
[2] Includes support equipment.
Source: Energy Information Administration, Form EIA-28.

Table B22. United States and Foreign Exploration and Development Expenditures and Production (Lifting) Costs for FRS Companies, 1989

(Million Dollars)

Expenditures	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	2,080	1,065	636	429	1,015
Drilling and Equipping					
Dry Holes (Cumulative)	-	1,042	380	662	-
Oil Wells (Cumulative)	-	223	82	141	-
Gas Wells (Cumulative)	-	468	202	266	-
Work-in-progress Adjustment	-	143	93	50	-
Total Drilling and Equipping	3,589	1,876	757	1,119	1,713
Geological and Geophysical	1,633	742	411	331	891
Other, Including Direct Overhead	2,150	1,224	675	549	926
Total Exploration Expenditures	9,452	4,907	2,479	2,428	4,545
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	5,398	2,170	1,240	930	3,228
Drilling and Equipping					
Dry Holes (Cumulative)	-	150	106	44	-
Oil Wells (Cumulative)	-	1,587	1,042	545	-
Gas Wells (Cumulative)	-	1,079	834	245	-
Work-in-progress Adjustment	-	1,024	515	509	-
Total Drilling and Equipping	6,826	3,840	2,497	1,343	2,986
Lease Equipment	4,242	2,029	1,187	842	2,213
Other Development					
Support Equipment	808	408	240	168	400
Other, Including Direct Overhead	2,391	1,635	1,330	305	756
Total Development Expenditures	19,665	10,082	6,494	3,588	9,583
Total Exploration and Development Expenditures	29,117	14,989	8,973	6,016	14,128
Production (Lifting) Costs					
Windfall Profit Tax	-19	-19	-	-	0
Other Severance and Production Taxes	3,279	2,301	-	-	978
Other Production Expenses	21,555	14,107	-	-	7,448
Total Production (Lifting) Costs	24,815	16,389	13,440	2,949	8,426
Total Expenditures and Costs Incurred	53,932	31,378	22,413	8,965	22,554

- = Not available.

Source: Energy Information Administration, Form EIA-28.

Table B23. Total Exploratory and Development Wells Drilled in the United States for FRS Companies and U.S. Industry, 1988 and 1989

Wells Drilled	U.S. Industry		FRS		All Other	
	1988	1989	1988	1989	1988	1989
Exploratory						
Dry	4,750	3,935	738	495	4,012	3,440
Successful	1,458	1,226	466	463	992	763
Oil	794	564	198	132	596	432
Gas	664	662	268	331	396	331
Subtotal	6,208	5,162	1,204	958	5,004	4,203
Percent Successful	23.5	23.8	38.7	48.3	19.8	18.2
Development						
Dry	5,373	4,435	422	330	4,951	4,105
Successful	20,371	18,726	5,008	4,018	15,363	14,708
Oil	12,670	9,929	3,903	2,765	8,767	7,164
Gas	7,701	8,797	1,105	1,253	6,596	7,544
Subtotal	25,744	23,162	5,430	4,348	20,314	18,814
Percent Successful	79.1	80.8	92.2	92.4	75.6	78.2
Total Wells Drilled	31,952	28,324	6,634	5,306	25,318	23,018

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review, June 1990* (September 1990), p. 73. FRS companies data - Energy Information Administration, Form EIA-28.

Table B24. Completed Well Costs, Oil, Gas, and Dry, for FRS Companies and U.S. Industry, 1988 and 1989

Drilling and Equipping Measures	FRS Companies			U.S. Industry			FRS as a Percent of U.S. Industry	
	1988	1989	Percent Change	1988	1989	Percent Change	1988	1989
Exploration								
Oil Wells								
Drilling and Equipping Costs[1]	291.0	223.0	-23.4	-	-	-	-	-
Wells Completed	198.0	131.9	-33.4	794.0	564.0	-29.0	24.9	23.4
Cost per Well (thousand dollars)	1,470	1,691	15.0	-	-	-	(2)	(2)
Average Depth (thousand feet)	8.6	8.9	3.0	6.1	5.8	-4.9	(2)	(2)
Cost per Foot (dollars)	170.28	190.11	11.6	-	-	-	(2)	(2)
Gas Wells								
Drilling and Equipping Costs[1]	649.0	468.0	-27.9	-	-	-	-	-
Wells Completed	268.0	330.7	23.4	664.0	662.0	-.3	40.4	50.0
Cost per Well (thousand dollars)	2,422	1,415	-41.6	-	-	-	(2)	(2)
Average Depth (thousand feet)	8.2	6.7	-18.8	6.6	6.1	-7.6	(2)	(2)
Cost per Foot (dollars)	293.80	211.38	-28.1	-	-	-	(2)	(2)
Dry Holes								
Drilling and Equipping Costs[1]	1,425.0	1,042.0	-26.9	-	-	-	-	-
Wells Completed	737.7	495.0	-32.9	4,750.0	3,935.0	-17.2	15.5	12.6
Cost per Well (thousand dollars)	1,932	2,105	9.0	-	-	-	(2)	(2)
Average Depth (thousand feet)	9.3	8.5	-8.1	5.6	5.3	-5.4	(2)	(2)
Cost per Foot (dollars)	207.70	246.39	18.6	-	-	-	(2)	(2)
Development								
Oil Wells								
Drilling and Equipping Costs[1]	2,018.0	1,587.0	-21.4	-	-	-	-	-
Wells Completed	3,903.0	2,765.2	-29.2	12,670.0	9,929.0	-21.6	30.8	27.8
Cost per Well (thousand dollars)	517	574	11.0	-	-	-	(2)	(2)
Average Depth (thousand feet)	4.5	4.6	3.6	4.2	3.9	-7.1	(2)	(2)
Cost per Foot (dollars)	115.58	123.89	7.2	-	-	-	(2)	(2)
Gas Wells								
Drilling and Equipping Costs[1]	1,032.0	1,079.0	4.6	-	-	-	-	-
Wells Completed	1,105.4	1,253.4	13.4	7,701.0	8,797.0	14.2	14.4	14.2
Cost per Well (thousand dollars)	934	861	-7.8	-	-	-	(2)	(2)
Average Depth (thousand feet)	6.8	6.4	-5.8	5.1	4.8	-5.9	(2)	(2)
Cost per Foot (dollars)	136.76	133.84	-2.1	-	-	-	(2)	(2)
Dry Holes								
Drilling and Equipping Costs[1]	187.0	150.0	-19.8	-	-	-	-	-
Wells Completed	421.5	330.1	-21.7	5,373.0	4,435.0	-17.5	7.8	7.4
Cost per Well (thousand dollars)	444	454	2.4	-	-	-	(2)	(2)
Average Depth (thousand feet)	6.5	6.4	-.6	4.7	4.6	-2.1	(2)	(2)
Cost per Foot (dollars)	68.72	70.82	3.1	-	-	-	(2)	(2)

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[1] Million Dollars.

[2] Not meaningful.

- = Not available.

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review, June 1990* (September 1990), p. 73. FRS companies data - Energy Information Administration, Form EIA-28.

Table B25. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1988 and 1989

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	1988	1989	Percent Change	1988	1989	Percent Change	1988	1989	Percent Change
Exploration									
Oil Wells									
Drilling and Equipping Costs[1]	291.0	223.0	-23.4	133.0	82.0	-38.3	158.0	141.0	-10.8
Wells Completed	198.0	131.9	-33.4	164.2	104.5	-36.4	33.8	27.4	-18.9
Cost per Well (thousand dollars)	1,470	1,691	15.0	810	785	-3.1	4,675	5,146	10.1
Average Depth (thousand feet)	8.6	8.9	3.0	8.3	8.5	2.1	10.1	10.4	2.8
Cost per Foot (dollars)	170.28	190.11	11.6	97.29	92.34	-5.1	461.99	494.74	7.1
Gas Wells									
Drilling and Equipping Costs[1]	649.0	468.0	-27.9	225.0	202.0	-10.2	424.0	266.0	-37.3
Wells Completed	268.0	330.7	23.4	202.4	269.6	33.2	65.6	61.1	-6.9
Cost per Well (thousand dollars)	2,422	1,415	-41.6	1,112	749	-32.6	6,463	4,354	-32.6
Average Depth (thousand feet)	8.2	6.7	-18.8	7.1	5.6	-20.7	11.8	11.4	-3.4
Cost per Foot (dollars)	293.80	211.38	-28.1	156.47	132.89	-15.1	549.94	383.29	-30.3
Dry Holes									
Drilling and Equipping Costs[1]	1,425.0	1,042.0	-26.9	583.0	380.0	-34.8	842.0	662.0	-21.4
Wells Completed	737.7	495.0	-32.9	573.5	394.9	-31.1	164.2	100.1	-39.0
Cost per Well (thousand dollars)	1,932	2,105	9.0	1,017	962	-5.3	5,128	6,613	29.0
Average Depth (thousand feet)	9.3	8.5	-8.1	8.7	8.0	-9.0	11.2	10.8	-3.5
Cost per Foot (dollars)	207.70	246.39	18.6	116.27	120.90	4.0	455.87	609.58	33.7
Development									
Oil Wells									
Drilling and Equipping Costs[1]	2,018.0	1,587.0	-21.4	1,631.0	1,042.0	-36.1	387.0	545.0	40.8
Wells Completed	3,903.0	2,765.2	-29.2	3,742.3	2,604.0	-30.4	160.7	161.2	.3
Cost per Well (thousand dollars)	517	574	11.0	436	400	-8.2	2,408	3,381	40.4
Average Depth (thousand feet)	4.5	4.6	3.6	4.3	4.3	2.0	9.7	9.4	-2.2
Cost per Foot (dollars)	115.58	123.89	7.2	102.52	92.30	-10.0	249.52	358.32	43.6
Gas Wells									
Drilling and Equipping Costs[1]	1,032.0	1,079.0	4.6	740.0	834.0	12.7	292.0	245.0	-16.1
Wells Completed	1,105.4	1,253.4	13.4	1,022.3	1,161.0	13.6	83.1	92.4	11.2
Cost per Well (thousand dollars)	934	861	-7.8	724	718	-.8	3,514	2,652	-24.5
Average Depth (thousand feet)	6.8	6.4	-5.8	6.5	6.1	-6.3	10.7	10.6	-.9
Cost per Foot (dollars)	136.76	133.84	-2.1	111.21	117.81	5.9	327.35	249.24	-23.9
Dry Holes									
Drilling and Equipping Costs[1]	187.0	150.0	-19.8	117.0	106.0	-9.4	70.0	44.0	-37.1
Wells Completed	421.5	330.1	-21.7	388.1	298.9	-23.0	33.4	31.2	-6.6
Cost per Well (thousand dollars)	444	454	2.4	301	355	17.6	2,096	1,410	-32.7
Average Depth (thousand feet)	6.5	6.4	-.6	6.3	6.2	-.5	8.8	8.3	-5.6
Cost per Foot (dollars)	68.72	70.82	3.1	48.23	57.05	18.3	237.29	169.23	-28.7

[1] Million Dollars.

Source: Energy Information Administration, Form EIA-28.

Table B26. U.S. Net Wells Completed, and Net In-Progress Wells for FRS Companies, 1983-1989

Wells	1983	1984	1985	1986	1987	1988	1989
Number of Net Wells Completed During Year							
Onshore							
Net Exploratory Wells							
Dry Holes	770	956	1,044	655	498	574	395
Oil Wells	390	475	454	282	253	164	105
Gas Wells	211	242	243	153	127	202	270
Total Exploratory Wells	1,371	1,672	1,741	1,089	877	940	769
Net Development Wells							
Dry Holes	566	641	647	493	330	388	299
Oil Wells	5,037	6,907	6,596	4,066	4,096	3,742	2,604
Gas Wells	942	1,009	1,066	645	615	1,022	1,161
Total Development Wells	6,545	8,557	8,309	5,204	5,040	5,153	4,064
Offshore							
Net Exploratory Wells							
Dry Holes	204	258	282	159	109	164	100
Oil Wells	62	71	63	34	23	34	27
Gas Wells	84	100	95	47	40	66	61
Total Exploratory Wells	350	429	440	240	172	264	189
Net Development Wells							
Dry Holes	35	53	57	43	29	33	31
Oil Wells	287	253	279	243	163	161	161
Gas Wells	114	122	189	93	60	83	92
Total Development Wells	436	427	525	379	252	277	285
Total United States							
Net Exploratory Wells							
Dry Holes	973	1,214	1,327	814	606	738	495
Oil Wells	452	545	517	316	276	198	132
Gas Wells	295	342	338	200	166	268	331
Total Exploratory Wells	1,721	2,101	2,181	1,330	1,049	1,204	958
Net Development Wells							
Dry Holes	601	694	704	537	359	422	330
Oil Wells	5,324	7,160	6,875	4,309	4,259	3,903	2,765
Gas Wells	1,056	1,131	1,254	738	675	1,105	1,253
Total Development Wells	6,981	8,984	8,833	5,583	5,293	5,430	4,349
Number of Net In-Progress Wells At Year End							
Onshore							
Exploratory Wells	342	421	389	170	220	152	301
Development Wells	1,414	1,783	1,609	555	798	694	813
Total In-Progress Wells	1,756	2,204	1,999	725	1,019	846	1,113
Offshore							
Exploratory Wells	170	176	150	88	136	73	62
Development Wells	173	199	166	92	113	128	109
Total In-Progress Wells	343	375	316	180	249	201	171
Total United States							
Exploratory Wells	513	597	539	258	356	224	363
Development Wells	1,586	1,982	1,776	647	911	822	922
Total In-Progress Wells	2,099	2,579	2,315	905	1,267	1,047	1,285

Source: Energy Information Administration, Form EIA-28.

Table B27. Exploration and Development Net Drilling Footage for FRS Companies, 1983-1989
(Thousand Feet)

Exploration, Development, and Production Statistics	1983	1984	1985	1986	1987	1988	1989
Onshore							
Exploratory							
Dry Hole Footage	6,629	7,625	9,160	6,072	4,388	5,014	3,143
Oil Well Footage	2,991	3,662	3,819	2,440	1,988	1,367	888
Gas Well Footage	2,354	2,573	2,141	1,288	981	1,438	1,520
Total Exploratory Footage	11,974	13,860	15,120	9,800	7,357	7,819	5,551
Development Well Footage							
Dry Hole Footage	4,073	4,341	4,395	3,821	2,251	2,426	1,858
Oil Well Footage	22,975	29,421	32,245	17,784	17,036	15,909	11,289
Gas Well Footage	8,547	8,461	9,060	5,963	4,878	6,654	7,079
Total Development Footage	35,595	42,223	45,700	27,568	24,165	24,989	20,226
Offshore							
Exploratory							
Dry Hole Footage	2,265	3,206	3,546	1,827	1,303	1,847	1,086
Oil Well Footage	655	752	698	396	252	342	285
Gas Well Footage	954	1,093	1,090	570	511	771	694
Total Exploratory Footage	3,874	5,051	5,334	2,793	2,066	2,960	2,065
Development Well Footage							
Dry Hole Footage	372	431	744	439	291	295	260
Oil Well Footage	2,646	2,234	2,747	2,532	1,690	1,551	1,521
Gas Well Footage	1,364	1,297	2,115	905	683	892	983
Total Development Footage	4,382	3,962	5,606	3,876	2,664	2,738	2,764

Source: Energy Information Administration, Form EIA-28.

Table B28. U.S. Net Producing Wells, and U.S. Acreage for FRS Companies, 1983-1989

Wells and Acreage	1983	1984	1985	1986	1987	1988	1989
Number of Net Producing Wells							
Onshore							
Oil Wells	178,536	185,870	191,011	178,027	174,568	167,018	143,852
Gas Wells	36,413	40,466	40,568	45,721	43,711	42,918	43,088
Total Producing Wells	214,950	226,336	231,579	223,748	218,279	209,936	186,940
Offshore							
Oil Wells	5,700	5,484	5,850	7,420	6,573	6,377	5,849
Gas Wells	3,448	3,371	3,722	3,342	3,571	3,026	3,205
Total Producing Wells	9,148	8,855	9,572	10,762	10,144	9,402	9,054
Total United States							
Oil Wells	184,236	191,354	196,861	185,446	181,141	173,395	149,701
Gas Wells	39,861	43,837	44,290	49,063	47,283	45,944	46,293
Total Producing Wells	224,097	235,191	241,151	234,509	228,424	219,339	195,994
	(thousand acres)						
Net Acreage							
Onshore							
Developed	30,082	29,704	30,005	33,351	31,208	33,068	32,864
Undeveloped	180,552	158,998	139,001	108,227	89,731	80,033	67,898
Offshore							
Developed	3,616	4,395	4,379	4,508	6,296	5,188	5,423
Undeveloped	12,728	18,216	18,904	14,520	16,055	19,619	22,010
Gross Acreage							
Onshore							
Developed	63,477	66,460	66,822	70,146	66,280	64,801	63,804
Undeveloped	280,109	255,319	221,215	165,582	135,463	117,028	104,114
Offshore							
Developed	8,056	8,301	10,142	10,242	10,552	11,134	10,532
Undeveloped	21,461	28,917	30,680	24,584	25,697	35,438	33,343

Source: Energy Information Administration, Form EIA-28.

Table B29. U.S. Net Petroleum Acreage for FRS Companies, Ranked by Total Energy Assets, 1989 and Percent Change from 1988

Petroleum Acreage	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Thousand Acres	Percent Change from 1986	Thousand Acres	Percent Change from 1988	Thousand Acres	Percent Change from 1988
Onshore						
Top Four	21,306	-19.0	12,321	-0.3	33,627	-13.1
Five Through Twelve	29,552	-18.2	11,519	-3.9	41,071	-14.7
All Other	17,040	-3.0	9,024	3.5	26,064	-.8
All FRS	67,898	-15.2	32,864	-.6	100,762	-10.9
Offshore						
Top Four	6,346	-2.9	2,934	3.1	9,280	-1.1
Five Through Twelve	12,966	24.7	1,622	-2.2	14,588	21.0
All Other	2,698	.4	867	26.9	3,565	5.8
All FRS	22,010	12.2	5,423	4.5	27,433	10.6
Total						
Top Four	27,652	-15.8	15,255	.3	42,907	-10.7
Percent Onshore	77.1	—	80.8	—	78.4	—
Five Through Twelve	42,518	-8.7	13,141	-3.7	55,659	-7.5
Percent Onshore	69.5	—	87.7	—	73.8	—
All Other	19,738	-2.5	9,891	5.2	29,629	-.1
Percent Onshore	86.3	—	91.2	—	88.0	—
All FRS	89,908	-9.8	38,287	.1	128,195	-7.0
Percent Onshore	75.5	—	85.8	—	78.6	—

-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B30. U.S. Net Ownership Interest Petroleum Reserves and Production for FRS Companies and U.S. Industry, 1989

Reserves and Production	Crude Oil and Natural Gas Liquids (billion barrels)		Natural Gas (trillion cubic feet)	
	FRS Companies	U.S. Industry	FRS Companies	U.S. Industry
Onshore				
Beginning Reserves	17.6	31.2	61.6	133.8
Ending Reserves	17.1	30.2	61.0	132.4
Percent Change	-2.4	-3.1	-1.0	-1.0
Production	1.6	2.9	4.9	12.0
Percent Change from 1988	-8.8	-7.3	2.7	1.1
Offshore				
Beginning Reserves	3.1	3.9	21.7	34.2
Ending Reserves	3.1	4.1	21.7	34.7
Percent Change	2.8	4.2	.1	1.4
Production	.3	.4	2.6	5.0
Percent Change from 1988	-10.9	-4.3	-9.5	3.9
Total				
Beginning Reserves	20.6	35.1	83.3	168.0
Ending Reserves	20.3	34.3	82.7	167.1
Percent Change	-1.6	-2.3	-.7	-.5
Production	1.9	3.3	7.5	17.0
Percent Change from 1988	-9.1	-7.0	-1.9	1.9

Note: 'Net Ownership Interest' is defined as Net working interest plus own royalty interest.

Sources: Industry data - Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report*, 1988 and 1989. FRS companies data - Energy Information Administration, Form EIA-28.

Table B31. Proved Petroleum Reserves for FRS Companies, United States and Foreign, 1989

Reserves Statistics	Worldwide Total	United States			Foreign		
		Total	Onshore	Offshore	Total	Canada	Other
	(million barrels)						
Crude Oil and Natural Gas Liquids							
Net Ownership Interest Reserves:							
Beginning of Period	32,419	20,620	17,564	3,056	11,799	2,754	9,045
Revisions of Previous Estimates	1,146	575	476	100	570	55	516
Improved Recovery	607	455	434	21	152	43	108
Purchases of Minerals-in-Place	575	219	209	10	356	322	34
Extensions & Discoveries	999	533	252	281	466	42	425
Production	-3,178	-1,911	-1,624	-287	-1,267	-213	-1,054
Sales of Minerals-in-Place	-547	-211	-172	-38	-336	-321	-15
End of period	32,021	20,281	17,139	3,143	11,740	2,681	9,059
Proportionate Interest in Investee Reserves and Foreign Access Reserves	1,524	—	—	—	1,524	W	W
	(billion cubic feet)						
Natural Gas							
Net Ownership Interest Reserves:							
Beginning of Period	133,481	83,264	61,614	21,651	50,217	14,244	35,973
Revisions of Previous Estimates	2,967	1,802	1,251	551	1,165	373	792
Improved Recovery	81	43	35	8	39	9	30
Purchases of Minerals-in-Place	3,131	1,390	978	412	1,742	1,724	18
Extensions & Discoveries	7,937	4,453	2,645	1,808	3,484	228	3,256
Production	-10,849	-7,481	-4,877	-2,603	-3,368	-853	-2,515
Sales of Minerals-in-Place	-2,537	-803	-650	-153	-1,734	-1,660	-75
End of Period	134,212	82,668	60,996	21,672	51,543	14,065	37,479

W = Data withheld to avoid disclosure.
— = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B32. U.S. Reserve Additions, Exploration and Development Expenditures, and Expenditures per Barrel of Reserve Additions for FRS Companies, Ranked by Total Energy Assets, and for U.S. Industry, 1987-1989

Reserve Additions, Expenditures, and Wells	1987			1988			1989		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
					(million barrels)				
Reserve Additions[1]									
Top Four	687.4	154.2	841.6	848.9	334.9	1,183.8	673.6	251.0	924.7
Five Through Twelve	1,801.9	269.6	2,071.6	969.5	271.4	1,240.9	900.3	504.7	1,405.0
All Other	127.6	100.2	227.8	507.4	200.7	708.1	284.4	65.6	350.0
All FRS	2,616.8	524.1	3,141.0	2,325.8	807.0	3,132.8	1,858.3	821.4	2,679.6
U.S. Industry	5,255.0	791.0	6,046.0	5,923.0	1,216.0	7,139.0	3,823.1	1,549.4	5,372.5
					(million dollars)				
Exploration and Development Expenditures									
Top Four	2,551.0	1,418.0	3,969.0	2,981.0	1,854.0	4,835.0	2,781.0	1,896.0	4,677.0
Five Through Twelve	3,902.0	1,808.0	5,710.0	5,185.0	2,726.0	7,911.0	3,560.0	2,585.0	6,145.0
All Other	1,215.0	753.0	1,968.0	2,296.0	922.0	3,218.0	1,392.0	605.0	1,997.0
All FRS	7,668.0	3,979.0	11,647.0	10,462.0	5,502.0	15,964.0	7,733.0	5,086.0	12,819.0
U.S. Industry	-	-	19,763.0	-	-	23,964.0	-	-	21,352.0
					(number of wells)				
Wells Completed									
Top Four	1,842.7	159.0	2,001.7	1,720.5	188.0	1,908.5	1,522.2	199.9	1,722.1
Five Through Twelve	3,002.9	195.7	3,198.6	2,832.1	247.2	3,079.3	2,103.1	207.3	2,310.4
All Other	1,071.4	68.0	1,139.4	1,540.2	105.6	1,645.8	1,207.6	66.2	1,273.8
All FRS	5,917.0	424.0	6,341.0	6,092.8	540.8	6,633.6	4,832.9	473.4	5,306.3
U.S. Industry	34,661.0	768.0	35,429.0	31,044.0	907.0	31,952.0	27,815.0	509.0	28,324.0
					(dollars per barrel)				
Exploration and Development Expenditures per Barrel of Reserve Additions									
Top Four	3.71	9.19	4.72	3.51	5.54	4.08	4.13	7.55	5.06
Five Through Twelve	2.17	6.71	2.76	5.35	10.04	6.37	3.95	5.12	4.37
All Other	9.52	7.51	8.64	4.53	4.59	4.54	4.90	9.22	5.71
All FRS	2.93	7.59	3.71	4.50	6.82	5.10	4.16	6.19	4.78
U.S. Industry	-	-	3.27	-	-	3.36	-	-	3.97
					(thousand barrels)				
Reserve Additions per Well Completed									
Top Four	373.0	970.1	420.2	493.4	1,781.5	620.3	442.5	1,255.8	536.9
Five Through Twelve	600.1	1,377.8	647.6	342.3	1,097.9	403.0	428.1	2,434.5	608.1
All Other	119.1	1,474.2	199.9	329.4	1,900.7	430.3	235.5	991.7	274.8
All FRS	442.3	1,236.2	495.3	381.7	1,492.3	472.3	384.5	1,735.0	505.0
U.S. Industry	151.6	1,029.9	170.7	201.2	1,340.7	237.0	137.4	3,044.0	189.7

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[1] Excludes net purchases of minerals in place, includes crude oil and natural gas liquids (measured in millions of barrels) and natural gas (measured in millions of barrels of crude equivalent). Excludes downward revisions of Alaskan North Slope natural gas reserves of 13.5 trillion cubic feet (Tcf) for FRS companies in 1987 and 24.6 Tcf for U.S. industry in 1988. The conversion factor for natural gas is 0.1772 barrels of crude / 1000 cubic feet. Reserve additions include the net of corrections and adjustments.

- = Not available.

Sources: Reserve additions - Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1987, 1988, and 1989 Annual Reports. Exploration and development expenditures - American Petroleum Institute, *Survey on Oil and Gas Expenditures, 1989* (Washington DC, November 1990). Wells completed - special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information's *Monthly Energy Review, June 1990* (September 1990), p. 73. FRS companies data - Energy Information Administration, Form EIA-28.

Table B33. Foreign Petroleum Exploration, Development, Reserves, and Production Statistics by Geographic Area for FRS Companies and Foreign Industry, 1989 and Percent Change from 1988

Foreign Petroleum Activities	Total Foreign	Canada	OECD Europe	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Crude Oil and NGL Production[1] (million barrels)							
FRS Companies	1,276.8	212.8	403.3	191.3	123.1	224.3	121.9
Percent Change	-4.5	1.4	-11.9	-.8	-5.0	7.1	-11.3
Foreign Industry[2]	14,563.8	719.4	1,504.2	2,239.6	6,174.7	1,343.6	2,582.3
Percent Change	5.3	-1.4	-1.1	8.0	9.0	3.0	1.5
Wells Completed							
FRS Companies	1,214.2	451.3	188.0	75.4	71.7	273.1	154.7
Percent Change	-35.6	-59.3	-2.3	-23.1	.6	10.1	-6.8
Foreign Industry	10,496.0	5,610.0	645.0	288.0	594.0	1,084.0	2,275.0
Percent Change	-27.3	-35.1	-29.8	-20.4	58.0	-23.2	-16.3
Success Rate[3]							
FRS Companies	69.7	67.1	57.4	58.2	81.3	75.6	82.2
Foreign Industry	75.9	74.0	65.0	68.8	81.8	79.8	81.3
Exploration and Development Expenditures (million dollars)							
FRS Companies	14,128.0	6,266.0	3,539.0	1,024.0	406.0	2,284.0	609.0
Percent Change	8.3	16.0	-18.1	21.9	8.0	66.8	-17.1
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	13,263.8	2,713.7	3,960.9	1,596.6	1,846.5	2,317.3	828.7
Percent Change	-.2	-1.3	3.8	.4	-2.0	-4.0	-.6

[1] Crude oil plus natural gas liquids. Includes ownership interest production and foreign access production.

[2] Foreign Industry levels defined as total activity outside of the United States except the People's Republic of China and the Soviet Bloc. Yugoslavia is excluded from Foreign Industry wells completed due to non-availability of data.

[3] Success Rate defined as the total number of successful well completions during the period divided by the total number of wells drilled.

[4] Includes net ownership interest reserves (88.4 percent) and 'Other Access' reserves (11.6 percent). Other access reserves include proportional interest in investee reserves and foreign access reserves.

Note: Sum of components may not equal total due to independent rounding.

Sources: FRS Companies - Energy Information Administration, Form EIA-28. Industry data - *World Oil*, August 15, 1990, and Energy Information Administration, *International Energy Annual*, 1989.

Table B34. Foreign Exploration and Development Expenditures by Region for FRS Companies, 1983-1989

(Million Dollars)

Foreign Expenditures by Region	1983	1984	1985	1986	1987	1988	1989
Exploration Expenditures							
Canada	862	1,013	899	508	562	1,124	1,141
OECD Europe	1,379	1,287	1,532	1,194	1,095	1,465	1,132
Africa	891	859	817	647	418	494	585
Middle East	126	165	164	110	124	223	197
Other Eastern Hemisphere	866	940	782	456	604	604	1,186
Other Western Hemisphere	285	274	290	297	266	316	304
Total Foreign Exploration Expenditures	4,408	4,537	4,484	3,213	3,069	4,226	4,545
Development Expenditures							
Canada	771	4,367	992	618	1,309	4,277	5,125
OECD Europe	2,880	4,179	2,188	1,974	1,889	2,854	2,407
Africa	773	2,532	769	417	337	346	439
Middle East	358	302	701	230	261	153	209
Other Eastern Hemisphere	1,183	1,091	551	730	2,162	765	1,098
Other Western Hemisphere	321	269	402	345	194	419	305
Total Foreign Development Expenditures	6,285	12,740	5,604	4,313	6,152	8,814	9,583
Total Exploration and Development Expenditures							
Canada	1,632	5,379	1,891	1,125	1,871	5,401	6,266
OECD Europe	4,259	5,466	3,719	3,168	2,984	4,319	3,539
Africa	1,663	3,391	1,586	1,064	755	840	1,024
Middle East	484	467	865	340	385	376	406
Other Eastern Hemisphere	2,049	2,031	1,333	1,186	2,766	1,369	2,284
Other Western Hemisphere	606	543	693	642	460	735	609
Total Foreign Exploration and Development Expenditures	10,693	17,278	10,088	7,526	9,221	13,040	14,128

Source: Energy Information Administration, Form EIA-28.

Table B35. Distribution of Foreign Exploration and Development Expenditures for FRS Companies Ranked by Total Energy Assets, 1989 and Percent Change from 1988

Exploration and Development Expenditures	Total Foreign	Canada	OECD Europe	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million dollars)					
1989						
All FRS	14,128.0	6,266.0	3,539.0	1,430.0	2,284.0	609.0
Top Four	8,750.0	5,222.0	1,720.0	437.0	1,164.0	207.0
Five Through Twelve	4,023.0	618.0	1,210.0	896.0	919.0	380.0
All Other	1,355.0	426.0	609.0	97.0	201.0	22.0
	(percent)					
Distribution 1989						
All FRS	100.0	44.4	25.0	10.1	16.2	4.3
Top Four	100.0	59.7	19.7	5.0	13.3	2.4
Five Through Twelve	100.0	15.4	30.1	22.3	22.8	9.4
All Other	100.0	31.4	44.9	7.2	14.8	1.6
Change from 1988						
All FRS	8.3	16.0	-18.1	17.6	66.8	-17.1
Top Four	84.4	219.0	4.1	-4.8	68.2	-31.9
Five Through Twelve	-43.0	-82.4	-40.2	33.5	77.1	15.9
All Other	9.9	74.6	-5.1	12.8	27.2	-78.6

Source: Energy Information Administration, Form EIA-28.

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Completed Wells in Foreign Areas for FRS Companies, 1983-1989

Number of Wells	1983	1984	1985	1986	1987	1988	1989
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	224.6	288.2	239.1	208.4	154.9	155.3	113.9
Oil Wells	220.8	200.3	136.1	117.1	114.4	84.1	56.3
Gas Wells	69.9	62.0	89.4	63.9	35.3	54.5	38.3
Total Exploratory Wells	515.3	550.5	464.6	369.4	304.6	293.9	208.5
Development Wells							
Dry Holes	30.4	36.6	38.5	57.8	32.2	58.2	34.7
Oil Wells	529.3	956.6	1,046.7	486.8	660.2	690.8	168.3
Gas Wells	57.2	52.4	149.9	52.6	49.2	66.6	39.8
Total Development Wells	616.9	1,045.6	1,235.1	597.2	741.6	815.6	242.8
Net In-Progress Wells at Year End	198.7	234.1	161.7	237.6	178.1	163.5	126.3
Net Producing Wells							
Oil Wells	10,907.6	12,476.8	12,045.5	13,072.7	13,187.5	16,087.6	15,880.1
Gas Wells	3,254.2	3,731.2	3,393.9	3,466.2	3,783.3	7,795.9	7,162.6
Total Producing Wells	14,161.8	16,208.0	15,439.4	16,538.9	16,970.8	23,883.5	23,042.7
OECD Europe							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	55.1	74.9	86.5	85.4	56.1	68.5	75.1
Oil Wells	19.6	28.0	28.4	15.9	14.6	15.8	13.7
Gas Wells	14.1	14.8	14.8	13.6	19.0	20.1	14.9
Total Exploratory Wells	88.8	117.7	129.7	114.9	89.7	104.4	103.7
Development Wells							
Dry Holes	7.2	14.1	9.2	3.6	3.0	8.6	4.9
Oil Wells	91.5	93.7	90.6	65.9	46.9	54.1	52.3
Gas Wells	13.7	25.7	15.3	24.4	7.8	25.4	27.1
Total Development Wells	112.4	133.5	115.1	93.9	57.7	88.1	84.3
Net In-Progress Wells at Year End	59.6	59.2	69.2	51.3	68.9	83.5	65.6
Net Producing Wells							
Oil Wells	1,711.5	1,799.4	1,879.7	1,736.5	1,750.7	1,532.9	1,436.8
Gas Wells	401.5	427.2	443.1	447.5	455.8	586.1	621.7
Total Producing Wells	2,113.0	2,226.6	2,322.8	2,184.0	2,206.5	2,119.0	2,058.5
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	49.6	43.9	64.9	48.2	44.9	55.3	37.8
Oil Wells	W	W	W	W	W	W	14.5
Gas Wells	W	W	W	W	W	W	1.7
Total Exploratory Wells	64.2	64.9	73.1	62.7	57.1	74.3	54.0
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	67.9	66.3	58.8	61.2	52.2	79.0	85.6
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	74.9	75.3	65.7	70.9	57.2	95.0	93.1
Net In-Progress Wells at Year End	54.3	54.2	68.6	58.5	52.8	47.0	46.0
Net Producing Wells							
Oil Wells	1,053.3	1,144.6	1,113.4	848.9	889.5	1,332.1	1,349.2
Gas Wells	13.8	18.8	21.9	22.6	38.0	19.9	20.4
Total Producing Wells	1,067.1	1,163.4	1,135.3	871.5	927.5	1,352.0	1,369.6
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	82.0	78.8	74.1	27.3	35.5	70.4	61.1
Oil Wells	18.3	33.9	21.5	11.1	13.3	16.9	19.9
Gas Wells	3.6	3.9	3.5	2.8	12.8	22.1	15.2
Total Exploratory Wells	103.9	116.6	99.1	41.2	61.6	109.4	96.2
Development Wells							
Dry Holes	8.3	5.4	7.5	3.9	1.0	2.9	5.5
Oil Wells	138.1	165.3	131.9	145.1	76.6	105.9	130.1
Gas Wells	25.7	40.4	59.0	29.1	22.0	29.8	41.3
Total Development Wells	172.1	211.1	198.4	178.1	99.6	138.6	176.9
Net In-Progress Wells at Year End	83.1	120.4	56.0	40.4	51.3	58.9	65.4
Net Producing Wells							
Oil Wells	866.3	908.1	1,164.8	1,211.6	1,202.6	1,312.2	1,468.3
Gas Wells	93.1	137.4	218.2	175.1	244.1	271.9	279.8
Total Producing Wells	959.4	1,045.5	1,383.0	1,386.7	1,446.7	1,584.1	1,748.1

See footnotes at end of table.

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Completed Wells in Foreign Areas for FRS Companies, 1983-1989 (Continued)

Number of Wells	1983	1984	1985	1986	1987	1988	1989
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	17.8	19.0	28.6	29.3	16.1	15.7	22.6
Oil Wells	6.7	W	W	W	W	W	W
Gas Wells	.0	W	W	W	W	W	W
Total Exploratory Wells	24.5	22.3	36.9	41.0	25.7	24.5	30.2
Development Wells							
Dry Holes	W	W	W	W	W	W	5.0
Oil Wells	89.8	84.8	112.6	125.6	117.7	140.6	119.5
Gas Wells	W	W	W	W	W	W	.0
Total Development Wells	94.8	96.3	117.0	158.2	121.7	141.4	124.5
Net In-Progress Wells at Year End	15.6	21.9	19.3	13.0	17.0	35.0	10.3
Net Producing Wells							
Oil Wells	3,943.8	4,523.7	3,780.1	3,424.6	3,413.8	3,277.0	3,276.8
Gas Wells	128.8	131.8	107.3	127.4	109.4	92.3	88.4
Total Producing Wells	4,072.6	4,655.5	3,887.4	3,552.0	3,523.2	3,369.3	3,365.2
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	429.1	504.8	493.2	398.6	307.5	366.2	310.5
Oil Wells	279.8	285.7	202.3	167.0	159.9	139.7	107.9
Gas Wells	87.8	81.5	107.9	83.6	71.3	100.6	74.2
Total Exploratory Wells	796.7	872.0	803.4	649.2	538.7	606.5	492.6
Development Wells							
Dry Holes	49.2	68.3	65.5	90.7	42.2	84.1	57.2
Oil Wells	916.6	1,366.7	1,440.6	884.6	953.6	1,070.4	555.8
Gas Wells	105.3	126.8	225.2	123.0	82.0	124.2	108.6
Total Development Wells	1,071.1	1,561.8	1,731.3	1,098.3	1,077.8	1,278.7	721.6
Net In-Progress Wells at Year End	411.3	489.8	374.8	400.8	368.1	387.9	315.6
Net Producing Wells							
Oil Wells	18,482.5	20,852.6	19,983.5	20,294.3	20,444.1	23,541.8	23,411.2
Gas Wells	3,891.4	4,446.4	4,184.4	4,238.8	4,630.6	8,766.1	8,172.9
Total Producing Wells	22,373.9	25,299.0	24,167.9	24,533.1	25,074.7	32,307.9	31,584.1

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B37. Foreign Proved Oil and Gas Reserves for FRS Companies, 1989

Reserves Statistics	Foreign					
	Total Foreign	Canada	OECD Europe	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million barrels)					
Crude Oil and Natural Gas Liquids						
Net Ownership Interest Reserves:						
Beginning of Period	11,799	2,754	3,735	2,491	1,987	832
Revisions of Previous Estimates & Improved Recovery	722	98	372	171	W	W
Net Purchases of Minerals-in-Place	20	0	27	0	W	W
Extensions & Discoveries	466	42	161	113	98	53
Production	-1,267	-213	-403	-304	-224	-122
End of Period	11,740	2,681	3,892	2,471	1,869	828
	(billion cubic feet)					
Natural Gas						
Net Ownership Interest Reserves:						
Beginning of Period	50,217	14,244	18,730	760	14,696	1,786
Revisions of Previous Estimates & Improved Recovery	1,203	382	474	W	377	W
Net Purchases of Minerals-in-Place	7	64	-57	0	0	0
Extensions & Discoveries	3,484	228	726	W	2,414	W
Production	-3,368	-853	-1,333	-39	-933	-209
End of Period	51,543	14,065	18,540	755	16,554	1,629

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B38. Foreign Production (Lifting) Costs for FRS Companies, 1983-1989
(Million Dollars)

Production Costs by Region	1983	1984	1985	1986	1987	1988	1989
Canada							
Royalty Expenses	364	223	W	W	W	W	19
Taxes other than Income Taxes	732	686	W	W	W	W	94
Other Costs	891	1,133	1,301	996	976	1,323	1,528
Total Production Costs	1,986	2,042	1,821	1,241	1,091	1,437	1,641
OECD Europe							
Royalty Expenses	602	656	732	402	420	300	224
Taxes other than Income Taxes	187	138	128	144	166	153	100
Other Costs	1,854	1,896	2,309	2,189	2,991	3,147	3,073
Total Production Costs	2,643	2,689	3,170	2,734	3,577	3,600	3,397
Africa							
Royalty Expenses	695	702	1,111	553	438	170	210
Taxes other than Income Taxes	177	22	55	21	15	31	14
Other Costs	710	712	867	671	495	575	480
Total Production Costs	1,582	1,436	2,032	1,245	948	776	704
Middle East							
Royalty Expenses	218	247	273	128	146	103	W
Taxes other than Income Taxes	202	295	304	118	154	72	W
Other Costs	206	199	261	309	286	273	295
Total Production Costs	626	741	837	555	586	448	454
Other Eastern Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	1,525	1,547	1,695	797	914	608	566
Other Costs	925	1,199	1,001	801	755	920	972
Total Production Costs	2,450	2,746	2,697	1,598	1,669	1,528	1,538
Other Western Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	704	627	501	287	302	196	210
Other Costs	471	547	472	393	412	387	482
Total Production Costs	1,175	1,174	973	681	714	583	692
Total Foreign							
Royalty Expenses	1,985	1,919	2,341	1,259	1,217	697	618
Taxes other than Income Taxes	3,421	3,225	2,978	1,435	1,453	1,050	978
Other Costs	5,057	5,686	6,211	5,359	5,915	6,625	6,830
Total Production Costs	10,463	10,830	11,530	8,053	8,585	8,372	8,426

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B39. U.S. Refining/Marketing Dispositions of Refined Products by Channel of of Distribution for FRS Companies, 1983-1989

U.S. Dispositions	1983	1984	1985	1986	1987	1988	1989
				Values (million dollars)			
Motor Gasoline							
Intersegment Sales	241	202	560	163	189	194	244
U.S. Third-Party Sales							
Wholesale-Resellers	35,451	34,247	34,669	24,796	26,394	25,313	26,451
Company Operated Automotive Outlets	11,497	10,902	11,647	8,419	9,101	9,733	11,308
Company Lessee and Open Automotive Outlets	25,663	25,596	24,853	17,271	19,445	20,284	23,050
Other (Industrial, Commercial and Other Retail)	4,882	4,044	7,994	3,486	5,107	5,045	4,566
Total Third-Party Sales	77,494	74,789	79,163	53,972	60,047	60,375	65,375
Total Motor Gasoline Sales	77,735	74,990	79,723	54,136	60,236	60,569	65,619
Distillate Fuels							
Intersegment Sales	494	491	417	231	214	311	398
Third-Party Sales	39,461	40,952	39,494	27,111	29,523	28,218	32,277
Total Distillate Fuels Sales	39,955	41,443	39,911	27,342	29,737	28,529	32,675
Other Refined Products							
Intersegment Sales	5,793	7,055	7,160	4,468	4,283	4,404	4,511
Third-Party Sales	26,387	26,864	24,634	17,060	20,481	17,388	19,124
Total Other Refined Products Sales	32,181	33,919	31,794	21,528	24,764	21,792	23,635
Total U.S. Refined Products							
Intersegment Sales	6,529	7,747	8,137	4,863	4,686	4,909	5,153
Third-Party Sales	143,342	142,604	143,291	98,143	110,051	105,981	116,776
Total U.S. Refined Products Sales	149,870	150,352	151,429	103,006	114,737	110,890	121,929
				Volumes (million barrels)			
Motor Gasoline							
Intersegment Sales	7	6	17	8	8	9	12
U.S. Third-Party Sales							
Wholesale-Resellers	956	993	991	1,173	1,109	1,107	1,007
Company Operated Automotive Outlets	277	275	289	312	318	340	356
Company Lessee and Open Automotive Outlets	672	706	666	687	718	742	768
Other (Industrial, Commercial and Other Retail)	132	116	231	163	245	262	184
Total Third-Party Sales	2,037	2,089	2,178	2,334	2,390	2,451	2,314
Total Motor Gasoline Sales	2,044	2,095	2,195	2,342	2,399	2,460	2,325
Distillate Fuels							
Intersegment Sales	15	15	14	13	10	16	16
Third-Party Sales	1,115	1,191	1,216	1,309	1,345	1,395	1,345
Total Distillate Fuels Sales	1,130	1,206	1,230	1,321	1,355	1,411	1,361
Other Refined Products							
Intersegment Sales	199	242	258	270	251	272	232
Third-Party Sales	866	869	896	967	1,044	1,010	1,004
Total Other Refined Products Sales	1,065	1,112	1,154	1,237	1,295	1,281	1,236
Total U.S. Refined Products							
Intersegment Sales	220	264	289	291	270	296	260
Third-Party Sales	4,018	4,149	4,290	4,610	4,779	4,855	4,663
Total U.S. Refined Products Sales	4,238	4,413	4,580	4,901	5,049	5,152	4,923
				Number of Automotive Outlets			
Number of Active Automobile Outlets at Year End							
Company Operated	8,507	8,801	9,369	9,327	9,837	10,712	10,995
Lessee Dealers	36,113	31,103	26,510	24,200	23,103	22,569	21,114
Open Dealers	50,744	52,440	30,030	30,033	28,279	32,919	21,475
Total Outlets	95,364	92,344	65,909	63,560	61,219	66,200	53,584

Source: Energy Information Administration, Form EIA-28.

Table B40. Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1988 and 1989
(Million Barrels and Dollars per Barrel)

Product Distribution Channel	All FRS		Top Four		Five Through Twelve		All Other	
	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Gasoline								
Intra-Company Sales								
1989	11.6	21.05	10.4	20.00	0.0	28.57	1.2	30.28
1988	8.7	22.21	6.9	21.68	.4	21.39	1.5	24.87
Percent Change	32.7	-5.2	51.3	-7.7	-90.6	33.6	-22.[illegible]	21.8
Wholesale/Resellers								
1989	1,006.6	26.28	320.7	25.87	474.3	26.44	211.5	26.55
1988	1,106.8	22.87	379.1	23.02	460.1	23.08	267.7	22.30
Percent Change	-3.1	14.9	-15.4	12.3	3.1	14.6	-21.0	19.0
Dealer-Operated Outlets								
1989	767.8	30.02	276.6	30.49	314.2	30.52	177.0	28.41
1988	741.8	27.34	300.1	27.61	310.0	27.62	131.7	26.09
Percent Change	3.5	9.8	-7.8	10.4	1.3	10.5	34.4	8.9
Company-Operated Outlets								
1989	355.6	31.80	103.0	33.26	168.2	30.51	84.4	32.58
1988	340.2	28.61	114.0	29.01	160.4	27.39	65.7	30.91
Percent Change	4.5	11.1	-9.7	14.7	4.8	11.4	28.4	5.4
Other[1]								
1989	183.6	24.87	33.0	24.69	68.6	25.14	82.0	24.73
1988	262.1	19.25	38.8	23.36	138.4	17.33	84.8	20.51
Percent Change	-30.0	29.2	-15.1	5.7	-50.5	45.1	-3.3	20.5
Total Gasoline								
1989	2,325.1	28.22	743.7	28.47	1,025.3	28.27	556.1	27.79
1988	2,459.6	24.63	838.9	25.48	1,069.3	24.29	551.4	23.96
Percent Change	-5.5	14.6	-11.3	11.7	-4.1	16.4	.8	16.0
Distillate								
1989	1,361.1	24.01	481.2	24.08	529.4	24.48	350.4	23.19
1988	1,410.6	20.22	507.2	20.51	557.9	20.14	345.5	19.95
Percent Change	-3.5	18.7	-5.1	17.4	-5.1	21.6	1.4	16.3
All Other Products								
1989	1,236.3	19.12	433.7	19.86	433.3	18.24	369.3	19.27
1988	1,281.3	17.01	477.3	17.32	452.2	15.44	351.8	18.59
Percent Change	-3.5	12.4	-9.1	14.7	-4.2	18.1	5.0	3.7
Total Refined Products								
1989	4,922.5	24.77	1,658.7	24.95	1,988.0	25.08	1,275.8	24.06
1988	5,151.5	21.53	1,823.3	21.96	2,079.4	21.25	1,248.7	21.34
Percent Change	-4.4	15.1	-9.0	13.6	-4.4	18.0	2.2	12.8

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[1] Includes direct sales to industrial and commercial customers and sales to unconsolidated affiliates.

Note: Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, Form EIA-28.

Table B41. U.S. Petroleum Refining/Marketing, General Operating Expenses for FRS Companies, 1983-1989

(Billion Dollars)

General Operating Expenses	1983	1984	1985	1986	1987	1988	1989
Raw Material Supply							
Raw Material Purchases	165.6	163.6	156.0	94.8	111.4	102.4	121.8
Other Raw Material Supply Expense	10.9	11.0	6.3	4.5	6.5	6.3	5.6
Total Raw Material Supply Expense	176.5	174.6	162.3	99.3	118.0	108.8	127.3
Less: Cost of Raw Materials Input To Refining	110.2	113.3	103.9	60.1	71.9	61.0	71.3
Net Raw Material Supply	66.3	61.4	58.4	39.2	46.1	47.8	56.0
Refining							
Raw Materials Input to Refining	110.2	113.1	103.9	60.1	71.9	61.0	71.3
Less: Raw Material Used as Refinery Fuel	6.7	6.7	6.3	4.6	3.9	3.7	3.9
Refinery Process Energy Expense	8.8	8.7	7.6	6.2	5.4	5.5	5.2
Other Refining Operating Expenses	7.1	7.8	8.4	7.7	8.2	8.9	8.6
Refined Product Purchases	20.2	20.2	20.4	16.7	21.9	20.5	24.4
Other Refined Product Supply Expenses	3.2	2.2	3.2	4.4	3.7	4.3	3.3
Total Refining	142.9	145.4	137.2	90.4	107.2	96.3	108.9
Marketing							
Cost of Other Products Sold	2.3	2.0	2.7	2.9	2.0	2.9	4.0
Other Marketing Expenses	6.6	8.2	9.8	9.7	9.3	8.1	8.9
Subtotal	8.9	10.1	12.5	12.6	11.3	11.0	12.9
Expense of Transport Services for Others	.4	.5	.5	.4	.4	.5	1.1
Total Marketing	9.3	10.7	13.0	13.0	11.7	11.5	14.0
Total U.S. Refining/Marketing Segment General Operating Expenses	218.4	217.4	208.7	142.6	165.0	155.6	178.9

Source: Energy Information Administration, Form EIA-28.

Table B42. U.S. Petroleum Segments' Purchases and Sales of Raw Materials and Refined Products for FRS Companies, 1983-1989

Purchases and Sales	1983	1984	1985	1986	1987	1988	1989
	Values (million dollars)						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	158,973	156,984	149,040	89,168	105,881	97,203	116,552
Natural Gas	3,235	3,259	3,796	3,081	2,993	2,878	3,237
Other Raw Materials	3,364	3,386	3,182	2,513	2,532	2,354	1,973
Total Raw Materials	165,573	163,629	156,018	94,763	111,406	102,435	121,762
Refined Products							
Motor Gasoline	7,210	6,745	9,550	7,648	9,987	10,332	11,095
Distillate Fuels	4,138	4,598	4,018	3,299	4,393	3,642	5,274
Other Refined Products	8,827	8,894	6,870	5,717	7,516	6,489	8,016
Total Refined Products	20,176	20,238	20,438	16,664	21,896	20,463	24,385
U.S. Production Segment							
Crude Oil and NGL	2,087	2,120	2,454	1,112	1,700	1,745	2,138
Natural Gas	3,131	4,320	4,001	2,732	2,034	2,702	2,845
Total Raw Materials	5,218	6,440	6,456	3,845	3,734	4,447	4,983
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	65,304	61,021	54,875	35,663	43,983	46,072	55,078
Natural Gas	1,734	1,660	2,264	2,240	2,548	2,188	2,262
Other Raw Materials	1,062	1,112	1,207	992	1,490	1,509	1,084
Total Raw Materials	68,101	63,794	58,345	36,895	48,021	49,769	58,424
Refined Products							
Motor Gasoline	77,735	74,990	79,723	54,136	60,236	60,569	65,619
Distillate Fuels	39,955	41,443	39,911	27,342	29,737	28,529	32,675
Other Refined Products	32,181	33,919	31,794	21,528	24,764	21,792	23,635
Total Refined Products	149,870	150,352	151,429	103,006	114,737	110,890	121,929
U.S. Production Segment							
Crude Oil and NGL	54,728	53,556	51,625	28,364	32,430	27,640	30,936
Natural Gas	18,417	21,976	19,873	14,894	12,789	15,241	14,965
Total Raw Materials	73,145	75,532	71,498	43,259	45,219	42,881	45,901
	Volumes						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	5,782	5,811	5,875	6,332	6,462	7,065	7,031
Natural Gas (billion cubic feet)	1,052	1,040	1,446	1,639	1,911	1,726	1,960
Refined Products (million barrels)							
Motor Gasoline	198	211	291	376	446	479	447
Distillate Fuels	141	139	128	157	216	195	236
Other Refined Products	325	288	259	370	371	383	442
Total Refined Products	664	638	678	903	1,032	1,058	1,125
U.S. Production Segment							
Crude Oil and NGL (million barrels)	104	118	132	95	152	166	184
Natural Gas (billion cubic feet)	1,222	1,799	1,734	1,507	1,401	1,761	1,802
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	2,189	2,118	2,136	2,336	2,577	3,122	3,226
Natural Gas (billion cubic feet)	602	552	958	1,220	1,489	1,310	1,350
Refined Products (million barrels)							
Motor Gasoline	2,044	2,094	2,195	2,342	2,399	2,460	2,325
Distillate Fuels	1,130	1,206	1,230	1,321	1,355	1,411	1,361
Other Refined Products	1,063	1,112	1,154	1,237	1,295	1,281	1,236
Total Refined Products	4,236	4,412	4,580	4,901	5,049	5,152	4,923
U.S. Production Segment							
Crude Oil and NGL (million barrels)	2,297	2,301	2,326	2,278	2,294	2,347	2,180
Natural Gas (billion cubic feet)	7,769	9,016	7,973	7,697	7,811	8,718	8,622

Source: Energy Information Administration, Form EIA-28.

Table B43. U.S. and Foreign Refining/Marketing Segment, Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies, 1983-1989

(Million Barrels)

Sources and Dispositions	1983	1984	1985	1986	1987	1988	1989
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	2,066	2,092	2,133	2,105	2,029	2,091	1,943
Purchases from Other U.S. Segments	78	42	73	293	270	424	337
Purchases from Third Parties and Unconsolidated Affiliates	2,820	2,801	2,941	3,063	3,264	3,643	3,917
Net Transfers from Foreign Refining/Marketing Segment	819	876	727	871	899	906	834
Total Sources	5,782	5,811	5,874	6,332	6,462	7,065	7,031
Dispositions							
Net Change in Inventories	-55	-61	-30	-42	-15	-22	15
Input to Refineries	3,648	3,754	3,769	4,039	3,900	3,965	3,790
Sales to:							
Unaffiliated Third Parties	2,135	2,046	2,069	2,181	2,528	2,734	2,849
Other Segments Excluding Foreign Refining/Marketing	55	72	66	154	50	388	377
Total Dispositions	5,782	5,811	5,874	6,332	6,462	7,065	7,031
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,164	1,278	1,325	1,298	1,261	1,253	1,196
Purchases							
Other Foreign Segments	78	22	56	41	68	49	22
Unconsolidated Affiliates	659	460	328	425	271	428	260
Unaffiliated Third Parties							
Foreign Access	365	210	131	134	155	129	156
Foreign Governments (Open Market)	587	701	438	467	370	374	495
Other Unaffiliated Third Parties	1,359	1,478	1,311	1,187	1,645	1,696	1,900
Net Transfers to U.S. Refining/Marketing Segment	-819	-876	-727	-871	-899	-906	-834
Total Sources	3,394	3,274	2,862	2,682	2,870	3,023	3,194
Dispositions							
Net Change in Inventories	-77	-38	23	60	3	1	-13
Input to Refineries	1,553	1,490	1,295	1,200	1,326	1,401	1,346
Sales	1,919	1,822	1,544	1,422	1,541	1,620	1,861
Total Dispositions	3,394	3,274	2,862	2,682	2,870	3,023	3,194

Source: Energy Information Administration, Form EIA-28.

Table B44. U.S. and Foreign Oil Raw Materials Balance for FRS Companies Ranked by Total Energy Assets, 1987-1989

(Million Barrels)

Geographical Sector	Raw Material Acquisitions				Total Refinery Input
	Direct Oil Access[1]	Net Oil Purchases[2]	Net Oil Imports	Oil Stock Changes[3]	
United States					
All FRS					
1989	2,158.1	812.7	834.3	-15.0	3,790.1
1988	2,225.3	811.2	906.4	22.3	3,965.2
1987	2,327.2	658.7	898.9	15.1	3,899.9
Top Four					
1989	829.1	243.6	217.1	-8.6	1,281.3
1988	767.6	261.6	424.6	6.3	1,460.2
1987	775.8	245.0	403.4	-9.0	1,415.1
Five Through Twelve					
1989	1,023.7	353.0	272.5	-6.6	1,642.6
1988	1,072.1	355.3	231.9	19.4	1,678.6
1987	1,257.0	134.8	230.8	9.1	1,631.8
All Other					
1989	305.3	216.0	344.6	.2	866.2
1988	385.7	194.3	249.9	-3.5	826.4
1987	294.4	278.9	264.7	15.0	853.1
Foreign					
All FRS					
1989	1,418.8	748.3	-834.3	12.8	1,345.7
1988	1,680.5	628.1	-906.4	-.9	1,401.3
1987	1,556.1	671.8	-898.9	-3.2	1,325.9
Top Four					
1989	938.3	480.4	-217.1	20.1	1,221.7
1988	1,195.5	512.3	-424.6	2.7	1,285.9
1987	1,040.3	578.1	-403.4	-10.9	1,204.1
All Other[4]					
1989	480.5	267.9	-617.1	-7.2	124.0
1988	485.0	115.8	-481.8	-3.6	115.4
1987	515.8	93.7	-495.5	7.8	121.8

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[1] Ownership interest production plus purchases from other company segments and from unconsolidated affiliates of crude oil and natural gas liquids (domestic and foreign areas) plus foreign access oil (foreign area only). Foreign access represents acquisitions from foreign entities, for which reporting firms act as producers under long-term contract.

[2] Purchases of crude and natural gas liquids (except imports) on the open market or from unaffiliated third parties less oil sales to unaffiliated third parties.

[3] Positive number indicates stock withdrawal (addition to supply).

[4] The 'Five Through Twelve' and 'All Other' groups combined into foreign 'All Other' to prevent disclosure.

Source: Energy Information Administration, Form EIA-28.

Table B45. U.S. Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for U.S. Industry, 1988 and 1989

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies				U.S. Industry	FRS Percent of Industry
	All FRS	Top Four	Five Through Twelve	All Other		
1989						
Refinery Output Volume[2]	11,413	4,153	4,794	2,466	15,655	72.9
Percent Gasoline	44.7	43.1	45.7	45.5	44.5	73.2
Percent Distillate	24.8	22.9	24.9	27.7	18.5	97.5
Percent Other	30.5	34.1	29.3	26.8	36.9	60.2
Refinery Capacity						
Year's Change (Net)	-792	-627	-121	-44	-47	1,685.1
At Year End	11,489	4,024	4,816	2,649	16,238	70.8
Utilization Rate[3]	85.4	78.8	89.5	88.6	85.2	([4])
1988						
Refinery Output Volume[2]	12,033	4,626	4,955	2,452	15,426	78.0
Percent Gasoline	44.5	43.1	45.4	45.7	45.7	76.0
Percent Distillate	25.1	23.8	24.9	27.8	27.2	71.9
Percent Other	30.4	33.1	29.7	26.5	27.0	87.6
Refinery Capacity						
Year's Change (Net)	-181	-138	96	-139	-296	61.1
At Year End	12,281	4,651	4,937	2,693	16,285	75.4
Utilization Rate[3]	86.1	82.6	91.1	83.0	82.7	([4])

[1] U.S. FRS and U.S. industry data include operations in Puerto Rico and the U.S. Virgin Islands.

[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

[3] Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.

[4] Not meaningful.

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Refinery output and refinery capacity: Energy Information Administration Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1988 and 1989. FRS companies data - Energy Information Administration, Form EIA-28.

Table B46. Foreign Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for Foreign Industry, 1988 and 1989

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies			Foreign Industry	FRS Percent of Industry
	All FRS	Top Four	All Other[2]		
1989					
Refinery Output Volume[3]	4,428	4,036	392	–	([5])
Percent Gasoline	28.5	27.7	36.7	–	([5])
Percent Distillate	39.8	40.3	35.5	–	([5])
Percent Other	31.7	32.0	27.8	–	([5])
Refinery Capacity					
Year's Change (net)	-94	-244	150	693	-13.6
At Year End	4,514	3,957	557	39,827	11.3
Utilization Rate[4]	76.6	76.9	73.4	–	([5])
1988					
Refinery Output Volume[3]	4,691	4,306	385	33,971	13.8
Percent Gasoline	28.7	27.3	44.9	20.9	19.0
Percent Distillate	39.0	39.3	35.6	37.4	14.4
Percent Other	32.2	33.4	19.5	41.7	10.7
Refinery Capacity					
Year's Change (net)	-17	12	-29	-307	5.5
At Year End	4,608	4,201	407	39,134	11.8
Utilization Rate[4]	77.2	76.8	81.1	.0	([5])

[1] Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China and the Soviet Bloc.

[2] 'Five through Twelve' and 'All Other' groups combined to avoid disclosure.

[3] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

[4] Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.

[5] Not meaningful.

– = Not available.

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Energy Information Administration, *International Energy Annual*, 1988 and 1989. FRS companies data - Energy Information Administration, Form EIA-28.

Table B47. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1983-1989

Refining Statistics	1983	1984	1985	1986	1987	1988	1989
	(thousand barrels per calendar day)						
U.S. Refining							
Runs to Stills							
At Own Refineries	9,850	10,255	10,315	10,664	10,536	10,646	10,147
By Refineries of Others	36	54	67	60	50	11	4
Total Runs to Stills	9,886	10,309	10,382	10,724	10,586	10,657	10,151
Refinery Output at Own Refineries and Refineries of Others							
Leaded Motor Gasoline	2,174	1,954	1,686	1,532	1,252	936	523
Unleaded Motor Gasoline	2,908	3,211	3,356	3,755	4,024	4,424	4,579
Total Motor Gasoline	5,082	5,165	5,042	5,287	5,276	5,360	5,102
Distillate Fuels	2,441	2,802	2,733	2,947	3,175	3,020	2,827
Other Refined Products	2,855	3,029	3,140	3,225	3,261	3,653	3,484
Total Refinery Output	10,378	10,996	10,915	11,459	11,712	12,033	11,413
Refinery Capacity at End of Year	13,014	12,771	12,614	12,526	12,462	12,281	11,489
	(number of refineries)						
Number of Wholly Owned Refineries	101	101	94	94	91	91	90
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	4,076	3,897	3,334	3,268	3,346	3,565	3,492
By Refineries of Others	630	584	590	644	709	836	685
Total Runs to Stills	4,706	4,481	3,924	3,912	4,055	4,401	4,177
Refinery Output at Own Refineries							
Motor Gasoline	1,144	1,111	1,050	1,001	1,011	1,078	1,044
Distillate Fuels	1,529	1,417	1,358	1,290	1,404	1,496	1,459
Other Refined Products	1,696	1,595	1,140	1,163	1,224	1,262	1,196
Total Refinery Output at Own Refineries	4,369	4,123	3,548	3,454	3,639	3,836	3,699
Refinery Output at Refineries of Others							
Motor Gasoline	171	164	192	209	229	270	218
Distillate Fuels	243	223	207	240	276	335	305
Other Refined Products	217	186	190	193	204	250	206
Total Refinery Output at Refineries of Others	631	573	589	642	709	855	729
Total Refinery Output	5,000	4,696	4,137	4,096	4,348	4,691	4,428
Refinery Capacity at End of Year	6,457	6,272	5,083	4,638	4,625	4,608	4,514
	(number of refineries)						
Number of Wholly Owned Refineries	45	44	37	34	32	31	28
Number of Partially Owned Refineries	21	19	17	16	17	17	18

Source: Energy Information Administration, Form EIA-28.

Table B48. U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1987-1989

Revenues and Costs	Million Dollars			Percent of Product Revenues		
	1987	1988	1989	1987	1988	1989
Refined Product Revenues	114,737.0	110,890.0	121,929.0	100.0	100.0	100.0
Refined Product Costs						
Raw Materials Processed[1]	66,071.0	55,254.0	64,994.0	57.6	49.8	53.3
Refinery Energy Expense	5,437.0	5,477.0	5,228.0	4.7	4.9	4.3
Other Refinery Expense	7,629.0	8,197.0	7,803.0	6.6	7.4	6.4
Product Purchases	21,896.0	20,463.0	24,385.0	19.1	18.5	20.0
Other Product Supply Expense	3,659.0	4,265.0	3,296.0	3.2	3.8	2.7
Marketing Expense[2]	9,305.0	8,070.0	8,938.0	8.1	7.3	7.3
Total Refined Product Costs	113,997.0	101,726.0	114,644.0	99.4	91.7	94.0
Refined Product Margin	740.0	9,164.0	7,285.0	6	8.3	6.0
Dollars per Barrel Margin[3]	.15	1.78	1.48	--	--	--
Other Refining/Marketing Revenues[4]	6,798.0	6,384.0	8,365.0	--	--	--
Other Refining/Marketing Expenses						
DD&A	2,685.0	2,732.0	2,883.0	--	--	--
Other[5]	3,874.0	5,048.0	7,026.0	--	--	--
Total Other Expenses	6,559.0	7,780.0	9,909.0	--	--	--
Refining/Marketing Operating Income	979.0	7,768.0	5,741.0	--	--	--
Miscellaneous Revenue & Expense[6]	355.0	505.0	527.0	--	--	--
Less Income Taxes	284.0	2,856.0	1,746.0	--	--	--
Refining/Marketing Net Income	1,073.0	5,443.0	4,522.0	--	--	--

[1] Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.

[2] Excludes cost of marketing tires, batteries, and accessories (TBA).

[3] Dollars per barrel of refined product sold.

[4] Includes revenues from transportation services supplied (non-federally regulated), TBA sales and miscellaneous.

[5] Includes general and administrative expenses, research and development costs, costs of transportation services supplied to others not included in raw material costs, and expenses for TBA.

[6] Includes other revenue and expense items, extraordinary items, and cumulative effect of accounting changes.

-- = Not applicable.

Source: Energy Information Administration, Form EIA-28.

Table B49. Sources of U.S. Bituminous Coal and Lignite Production, by Region and Mining Method, for FRS Companies and U.S. Industry, 1989 and Percent Change From 1988

Production	Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
	(million tons)					
1989						
FRS Companies	286.9	114.0	37.7	135.1	123.9	163.0
U.S. Industry	980.7	464.5	134.5	381.7	393.8	586.9
	(percent)					
Distribution by Region, 1989						
FRS Companies	100.0	39.8	13.1	47.1	--	--
U.S. Industry	100.0	47.4	13.7	38.9	--	--
Distribution by Mining Method, 1989						
FRS Companies	100.0	--	--	--	43.2	56.8
U.S. Industry	100.0	--	--	--	40.2	59.8
FRS Companies as a Percent of U.S. Industry	29.3	24.6	28.0	35.4	31.5	27.8
Change from 1988						
FRS Companies	.6	5.1	-2.9	-2.0	-.7	1.6
U.S. Industry Total	3.2	3.4	3.3	3.0	3.1	3.3

-- = Not applicable.

Sources: Industry data - Energy Information Administration Form EIA-7A, see *Coal Production 1989*, (December 1990). FRS companies data - Energy Information Adminstration, Form EIA-28.

Table B50. U.S. Coal Reserves Balance for FRS Companies, 1983-1989

(Million Tons)

Reserves Balance	1983	1984	1985	1986	1987	1988	1989
Changes to U.S. Coal Reserves							
Beginning of Period	63,304	66,106	64,761	54,153	49,629	54,595	51,710
Changes due to:							
Leases/Purchases of Minerals-in-Place	225	97	586	119	304	521	417
Corporate Mergers and Acquisitions	59	1,075	749	672	764	W	W
Other Reserve Changes	4,327	4	-860	-139	6,505	W	W
Production	-185	-226	-230	-228	-255	-285	-287
Dispositions of Minerals-in-Place	-1,624	-2,294	-10,853	-4,924	-2,352	-653	-793
End of Period Reserves	66,106	64,761	54,153	49,653	54,595	53,067	49,200
Weighted Average Annual Production Capacity	268	274	291	283	303	313	322

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B51. U.S. Coal Reserves (End of Year) and Production Statistics for FRS Companies, 1983-1989

(Million Tons)

Reserves and Production Statistics	U.S. Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
1983						
U.S. Coal Reserves	66,105.9	14,392.6	9,338.0	42,375.3	20,157.0	45,948.8
U.S. Coal Production	185.2	72.5	28.5	84.2	73.5	111.7
1984						
U.S. Coal Reserves	64,761.3	13,736.0	9,083.3	41,942.0	19,532.7	45,228.6
U.S. Coal Production	226.0	81.4	38.0	106.5	91.2	134.8
1985						
U.S. Coal Reserves	54,152.9	9,259.9	8,505.1	36,387.9	18,556.2	35,596.6
U.S. Coal Production	230.4	82.9	36.4	111.0	96.2	134.1
1986						
U.S. Coal Reserves	49,653.3	8,998.8	7,449.0	33,205.5	16,736.0	32,917.3
U.S. Coal Production	227.6	84.0	41.7	101.9	101.6	126.0
1987						
U.S. Coal Reserves	54,595.2	13,069.2	7,371.2	34,154.8	16,549.5	38,045.7
U.S. Coal Production	255.3	98.3	41.7	115.3	114.5	140.8
1988						
U.S. Coal Reserves	53,067.2	12,656.0	7,256.2	33,154.9	16,287.1	36,780.1
U.S. Coal Production	285.3	108.5	38.8	138.0	124.8	160.5
1989						
U.S. Coal Reserves	49,200.2	11,462.1	7,324.2	30,413.9	15,783.7	33,416.4
U.S. Coal Production	286.9	114.0	37.7	135.1	123.9	163.0

Source: Energy Information Administration, Form EIA-28.

Table B52. Research and Development Expenditures for FRS Companies, 1983-1989
(Million Dollars)

Research and Development Expenditures	1983	1984	1985	1986	1987	1988	1989
Sources of R&D Funds							
Federal Government	93	104	89	15	17	14	11
Internal Company	3,692	3,945	3,999	3,554	3,451	3,667	3,664
Other Sources	27	15	20	11	20	18	28
Total Sources	3,812	4,064	4,108	3,581	3,488	3,699	3,703
Breakdown of R&D Expenditures							
Oil & Gas Recovery	756	692	801	645	666	726	694
Other Petroleum	487	614	536	496	463	496	575
Coal Gasification/Liquefaction	159	102	117	69	47	34	W
Other Coal	34	35	24	21	17	18	W
Nuclear and Other Energy	317	369	293	170	91	85	93
Nonenergy	1,971	2,157	2,212	2,055	2,166	2,307	2,148
Unassigned	88	94	125	125	38	33	142
Total Expenditures	3,812	4,064	4,108	3,581	3,488	3,699	3,703

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28.

Glossary

Acquisition Costs: Direct costs and indirect costs incurred to acquire legal rights to wasting natural resources. Direct costs include costs incurred to obtain options to lease or purchase mineral rights and costs incurred for the actual leasing (e.g., lease bonuses) or purchasing of the rights. Indirect costs include such costs as: brokers' commissions and expenses; abstract and recording fees; filing and patenting fees; and costs of legal examination of title and documents.

Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. (See definition for Working Interest.) A distinction may be made between "gross" acreage and "net" acreage:

- **Gross.** All acreage covered by any working interest, regardless of the percentage of ownership in the interest.

- **Net.** Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.

Affiliate: An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified. The term "affiliate" includes any subsidiary or parent of the person specified.

Amortization: The depreciation, depletion, or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with nonproducing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration, and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Branded Product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Christmas Tree: The valves and fittings installed at the top of a gas or oil well to control and direct the flow of well fluids.

Coal Gasification: The process of converting coal into gas. The basic process involves crushing coal to a powder, which is then heated in the presence of steam and oxygen to produce a gas. The gas is then refined to reduce sufur and other impurities. The gas can be used as a fuel or processed further and concentrated into chemical or liquid fuel.

Coal Liquefaction: A chemical process that converts coal into clean-burning liquid hydrocarbons, such as synthetic crude oil and methanol.

Coal Regions: The following regional definitions are used to report domestic coal reserves, production, and other operating statistics.

- **Eastern Region.** Consists of the Northern Appalachian Coal Basin. The following States comprise the Eastern Region: Alabama, Georgia, Ohio, Maryland, Mississippi, Pennsylvania, Virginia, Tennessee, North Carolina, West Virginia, and Eastern Kentucky.

- **Midwest Region.** Consists of the Illinois and Michigan Coal Basins. The following States comprise the Midwest Region: Illinois, Indiana, Michigan, and Western Kentucky.

- **Western Region.** Consists of the Northern Rocky, Southern Rocky, Western Interior, and West Coast Coal Basins. The following States comprise the Central Western Region: Alaska, Arizona, Arkansas, California, Colorado, Idaho, Iowa, Kansas, Louisiana, Missouri, Montana, New Mexico, North Dakota, Oklahoma, Oregon, Texas, South Dakota, Utah, Washington, and Wyoming.

Company Automotive (Retail) Outlet: Any retail outlet selling motor fuel under a reporting company brand name. (See definition for Branded Product.)

- **Company Operated.** A company retail outlet which is operated by salaried or commission personnel paid by the reporting company.

- **Lessee.** An independent marketer who leases the station and land and has use of tanks, pumps, signs, etc. A lessee dealer typically has a supply agreement with a refiner or a distributor and purchases products at dealer tank wagon prices. The term "lessee dealer" is limited to those dealers who are supplied directly by a refiner or any affiliate or subsidiary company of a refiner. "Direct supply" includes use of commission agent or common carrier delivery.

- **Open.** An independent marketer who owns or leases (from a third party who is not a refiner) the station or land of a retail outlet and has use of tanks, pumps, signs, etc. An open dealer typically has a supply agreement with a refiner or a distributor and purchases products at or below dealer tank wagon prices.

Contribution to Net Income: The FRS segment equivalent of net income. However, many consolidated items of revenue and expense are not allocated to the segments, and therefore they are not equivalent in a strict sense. The largest item not allocated to the segments is interest expense since this is regarded as a corporate-level item for FRS purposes.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For FRS reporting, volumes reported as crude include:

- Liquids technically defined as crude oil.
- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production and reserves are reported as liquid equivalents at the surface (excluding base sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, corrected to 60 degrees Fahrenheit.

Where a State regulatory agency specifies a definition of crude oil which differs from that set forth above for statistical purposes, the State definition should be followed.

DD&A: Abbreviation for depreciation, depletion and amortization.

Deferred Taxes: Taxes accrued and reflected as an expense in a company's income statement, but not payable to the taxing authority in that time period. These taxes are accrued to compensate for an understatement of income tax expense which would occur if only the tax currently due to the taxing authority were reflected as the total income tax expense.

Depletion: A term for either (1) a periodic assignment to expense of recorded amounts or (2) an allowable income tax deduction that is related to the exhaustion of mineral reserves. Depletion is included as one of the elements of amortization. When used in that manner, depletion refers only to book depletion (see definition for Amortization).

- **Book.** The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.

- **Tax-cost.** A deduction (allowance) under U.S. Federal Income taxation normally calculated under a formula whereby the adjusted basis of the mineral property is multiplied by a fraction, the numerator of which is the number of units of minerals sold during the tax year and the denominator of which is the estimated number of units of unextracted minerals remaining at the end of the tax year plus the number of units of minerals sold during the tax year.

- **Tax-percentage (or Statutory).** A deduction (allowance) allowed to certain mineral producers under U.S. Federal income taxation calculated on the basis of a specified percentage of gross revenue from the sale of minerals from each mineral property not to exceed the lesser of 50 percent of the taxable income from the property computed without allowance for depletion. (There are also other limits on percentage depletion on oil and gas production.) The taxpayer is entitled to a deduction representing the amount of tax-cost depletion or percentage (statutory) depletion, whichever is higher.

- **Excess Statutory Depletion.** The excess of estimated statutory depletion allowable as an income tax deduction over the amount of cost depletion otherwise allowable as a tax deduction, determined on a total enterprise basis.

Depreciation: See definition for Amortization.

Development: The preparation of a specific mineral deposit for commercial production; this preparation includes construction of access to the deposit and of facilities to extract the minerals. The development process is sometimes further distinguished between a preproduction stage and a current stage, with the distinction being made on the basis of whether the development work is performed before or after production from the mineral deposit has commenced on a commercial scale.

Development Costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas.

Drilling: The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids).

- **Exploratory.** Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.
- **Developmental.** Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.
- **Directional.** Drilling that is deliberately made to depart significantly from the vertical.

Drilling and Equipping of Wells: The drilling and equipping of wells through completion of the "christmas tree."

Dry-Hole Charge: The charge-off to expense of a previously capitalized cost upon the conclusion of an unsuccessful drilling effort.

Equity in Earnings of Unconsolidated Affiliates: A company's proportional share (based on ownership) of the net earnings or losses of an unconsolidated affiliate.

Exploration: The identification of areas that may warrant examination and to examine specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property.

Exploration Costs: Costs, including depreciation and applicable operating costs, of support equipment and facilities and other costs directly identifiable with exploration activities, such as:

- Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these costs are sometimes referred to as geological and geophysical or "G&G" costs.
- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.
- Dry hole contributions and bottom hole contributions.
- Costs of drilling and equipping exploratory wells.
- Costs of drilling exploratory-type stratigraphic test wells.

Extraordinary Item: Income and expense items associated with events and transactions that possess a high degree of abnormality and are of a type that would not reasonably be expected to recur in the foreseeable future.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Footage Drilled: Total footage for wells in various categories, as reported for any specified period, includes (1) the deepest total depth (length of well bores) of all wells drilled from the surface, (2) the total of all bypassed footage drilled in connection with reported wells, and (3) all new footage drilled for directional "sidetrack" wells. Footage reported for directional "sidetrack" wells does not include footage in the common bore which is reported as footage for the original well. In the case of old wells drilled deeper, the reported footage is that which was drilled below the total depth of the old well.

- **Deepest Total Depth.** The deepest total depth of a given well is the distance from a surface reference point (usually the Kelly bushing) to the point of deepest penetration measured along the well bore. If a well is drilled from a platform or barge over water, the depth of the water is included in the total length of the well bore.
- **Sidetrack Drilling.** This is a remedial operation that results in the creation of a new section of well bore for the purpose of (1) detouring around junk, (2) redrilling lost hole, or (3) straightening key seats and crooked holes. Directional "sidetrack" wells do not include footage in the common bore which is reported as footage for the original well.

Foreign Access: Refers to proved reserves of crude (including lease condensate) and natural gas liquids applicable to long-term supply agreements with foreign governments or authorities in which the company acts as producer.

Foreign Operations: These are operations that are located outside the United States. Determination of whether an enterprise's mobile assets, such as offshore drilling rigs or ocean-going vessels, constitute foreign operations should depend on whether such assets are normally identified with operations located outside the United States.

Foreign operations are segregated into the following areas for FRS reporting purposes:

- **OECD Europe.** Includes Austria, Belgium, Denmark, Finland, France, the Federal Republic of

Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

- **Middle East.** Includes Saudi Arabia, the United Arab Emirates, Iraq, Iran, Kuwait, the Iraq-Saudi Arabia Neutral Zone, Qatar, Dubai, Bahrain, Oman, Yemen, Syria, Jordan, and Israel.
- **Canada.**
- **Africa** (the African continent).
- **Other Eastern Hemisphere.** Areas eastward of the Greenwich prime meridian to 180 degrees longitude and not included in other specified domestic or foreign classifications.
- **Other Western Hemisphere.** Areas westward of the Greenwich prime meridian to 180 degrees longitude not included in other domestic or foreign classifications.

Funds From Operations: Calculated by adding noncash charges back to net income or contribution to net income. Deferred taxes and depreciation, depletion, and amortization (DD&A) are the largest noncash charges.

Funds, Total Sources of: The total source of funds including net income plus noncash charges such as DD&A and deferred taxes, issuances of stocks and bonds, and proceeds from the sale or property, plant, and equipment. The concept is similar to cash flow generated, but does not attempt to account for changes in working capital items. Thus, for example, an inventory buildup or drawdown would not be accounted for under the "funds" concept since both cash and inventory are items of working capital.

Geological and Geophysical (G&G) Costs: Costs incurred in making geological and geophysical studies, including, but not limited to, costs incurred for salaries, equipment, obtaining rights of access, and supplies for scouts, geologists, and geophysical crews.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in either the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (e.g., methane, a constituent of natural gas) to the very heavy and very complex.

Improved Recovery: The operation whereby crude oil or natural gas is recovered using any method other than those that rely primarily on the use of natural reservoir pressure, gas lift or the use of a pump.

Intangible Drilling and Development Costs (IDC): Costs incurred in preparing well locations, drilling and deepening wells, and preparing wells for initial production up through the point of installing control valves. None of these functions, because of their nature, have salvage value. Such costs would include labor, transportation, consumable supplies, drilling tool rentals, site clearance, and similar costs.

Investment and Advances to Unconsolidated Affiliates: The balance sheet account representing the cost of investments and advances to unconsolidated affiliates. Generally, affiliates which are less than 50 percent owned by a company may not be consolidated into the company's financial statements.

Lease Bonus. An amount paid by a lessee to a lessor as consideration for granting a lease, usually as a lump sum; this payment is in addition to any rental or royalty payments.

Lease Equipment: All equipment located on the lease except the well and the complete christmas tree installation.

Lifting Costs: The costs associated with the extraction of a mineral reserve from a producing property. (See definition for Production Cost.)

Mining: Any activity directed to the extraction of ore and associated rock. Included are open pit work, quarrying, augering, alluvial dredging, and combined operations, including surface and underground operations.

Mineral: Any of the various naturally occurring substances (such as coal, crude oil, metals, natural gas, salt, sand, stone, sulfur, and water) usually obtained from the earth. The term is used to include all wasting, i.e., nonregenerative, inorganic substances that are extracted from the earth.

Mineral Interests in Properties (hereinafter referred to as Properties): These include fee ownership or a lease, concession, or other contractual interest representing the right to extract minerals subject to such terms as may be imposed by the conveyance of those interests. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as "producer" of the underlying reserves, but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Mineral Lease: An agreement wherein a mineral interest owner (lessor) conveys to another party (lessee) the rights to explore for, develop, and produce specified minerals. The lessee acquires a working interest and the lessor retains a nonoperating interest in the property, referred to as the royalty interest, each in proportions agreed upon.

Mineral Rights: The ownership of the minerals beneath the earth's surface with the right to remove them. Mineral rights may be conveyed separately from surface rights.

Minority Interest in Income: The proportional share of the minority ownership's interest (less than 50 percent) in the earnings or losses of the consolidated subsidiary.

Subsidiaries are generally fully consolidated when a share of ownership between 51 percent and 100 percent is held by the parent. In consolidation, 100 percent of revenues, expenses, assets, etc. are included in the financial statements even though, for example, the subsidiary is only 80 percent owned by the parent company. In such cases, the consolidated balance sheet must have a caption on the right-hand side titled something like "minority interests in consolidated affiliates," and the income statement must have a similar line to reduce net income to the *pro rata* (80 percent in this example) share of the consolidated subsidiary's net income.

Motor Gasoline: Refers to blended gasoline suitable as fuel for use in spark ignition systems and within American Society for Testing and Materials (ASTM) specifications D 439.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes, and pentanes. Typical nonhydrocarbon bases which may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances.

Natural gas, based on the type of occurrence in the reservoir, is classified by two categories, as follows:

- **Non-Associated Gas** is natural gas that is not in contact with significant quantities of crude oil in the reservoir.
- **Associated/Dissolved Gas** is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas that is in solution with crude oil in the reservoir at reservoir conditions.

Statistical data pertaining to natural gas production and reserves are reported in units of 1,000,000 cubic feet (i.e., MMCF) at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit for FRS purposes.

Natural Gas Liquids (NGL): Natural gas liquids are those portions of reservoir gas which are liquefied at the surface in lease separators, field facilities, or gas processing plants. Natural gas liquids include but are not limited to: ethane, propane, butanes, pentanes, natural gasoline and condensate.

Net Investment in Place: The sum of net property, plant, and equipment (PP&E) plus investment and advances to unconsolidated affiliates.

Nonbranded Product: Any refined petroleum product that is not a branded product.

Nuclear Fuel Operations: All nuclear fuel operations, excluding reactor and reactor component manufacturing or containment construction. Includes exploration and development; mining; milling; conversion; enrichment; fabrication; reprocessing; and spent fuel storage.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

If a State agency uses a different basis for classifying onshore and offshore areas, the State classification should be used. (Cook Inlet in Alaska is classified as offshore.)

Oil Shale: A sedimentary rock containing kerogen, a solid organic material.

Operating Expenses: Segment expenses related both to revenue from sales to unaffiliated customers and revenue from intersegment sales or transfers, excluding loss on disposition of property, plant, and equipment; interest expenses and financial charges; foreign currency translation effects; minority interest; and income taxes.

Operating Income: Operating revenues less operating expenses. Excludes items of other revenue and expense such as equity in earnings of unconsolidated affiliates, dividends, interest income and expense, income taxes, extraordinary items, and cumulative effect of accounting changes.

Operating Revenues: Segment revenues both from sales to unaffiliated customers (i.e., revenue from customers outside the enterprise as reported in the company's consolidated income statement) and from intersegment sales or transfers, if any, of product and services similar to those sold to unaffiliated customers, excluding equity in earnings of unconsolidated affiliates; dividend and interest income; gain on disposition of property, plant, and equipment; and foreign currency translation effects.

Other Energy Operations: Energy operations not included in Petroleum or Coal. Other Energy includes nuclear fuel, oil shale, tar sands, geothermal, and coal liquefaction and gasification.

PP&E, Additions to: The current year's expenditures on property, plant, and equipment (PP&E). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS will be a function of each reporting company's policy.

PP&E, Net: The original cost of property, plant, and equipment (PP&E), less accumulated depreciation.

Petroleum: Hydrocarbon mixtures broadly defined to include crude oil, lease condensate, natural gas, products of natural gas processing plants (plant products), refined products, and semifinished products and blending materials.

Pipelines, Rate Regulated: FRS establishes three pipeline segments; crude/liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all federally or state rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option intrastate pipeline operations may be included in the U.S. Refining/Marketing Segment if: they would comprise less than 5 percent of U.S. Refining/Marketing Segment net PP&E, revenues and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PP&E reported for the U.S. Refining/Market Segment.

Primary Recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure (energy or gravity).

Primary Transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Producing Property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Production, Natural Gas Liquids: Production of natural gas liquids is classified as follows:

- **Contract Production.** Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.
- **Leasehold Production.** Natural gas liquids produced, extracted, and credited to a company's interest.
- **Contract Reserves.** Natural gas liquid reserves corresponding to the contract production defined above.
- **Leasehold Reserves.** Natural gas liquid reserves corresponding to the leasehold production defined above.

Production, Oil and Gas: The lifting of the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

- **Gross Company-Operated Production.** Total production from all company operated properties including all working and nonworking interests.
- **Net Working Interest Production.** Total production accruing to the reporting company's working interests less royalty oil and volumes due others.

Production Costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs):

- Costs of labor to operate the wells and related equipment and facilities.
- Repair and maintenance costs.
- The costs of materials, supplies and fuel consumed and services utilized in operating the wells and related equipment and facilities.
- The costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
- The costs of severance taxes.

Depreciation, depletion, and amortization (DD&A) of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Production costs include the following subcategories of costs:

- Well operations and maintenance
- Well workovers
- Operating fluid injection and improved recovery programs
- Operating gas processing plants
- *Ad valorem* taxes
- Production or severance taxes
- Other, including overhead

Research and Development: Basic and applied research in the sciences and engineering and the design and development of prototypes and processes, excluding quality control, routine product testing, market research, sales promotion, sales service, research in the social sciences or psychology, and other non-technological activities or technical services.

Reserves (Coal): Coal reserve estimates comprising the demonstrated coal reserve base include only proved (measured) and probable (indicated).

- **Proved (Measured) Reserves.** Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.
- **Probable (Indicated) Reserves.** Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on geologic evidence. The sites available are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Reserves, Proved (Oil and Gas): The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

For natural gas an appropriate reduction in the reservoir gas volume is made to cover the removal of the liquefiable portions of the gas and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. If the liquefiable portions of the gas are not separately estimated, they need not be separately stated for FRS reporting purposes.

Reserves, Net: Includes all proved reserves associated with the company's net working interests. (See definition for Working Interest.)

Reserves, Change in: For FRS reporting, the following definitions should be used for changes in reserves.

- **Revisions of Previous Estimates.** Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.
- **Improved Recovery**. Changes in reserve estimates resulting from application of improved recovery techniques shall be separately shown, if significant. If not significant, such changes shall be included in revisions of previous estimates.
- **Purchases or Sales of Minerals-in-Place**. Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.
- **Extensions, Discoveries, and Other Additions.** Additions to an enterprise's proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Reservoir: A porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Residual Fuel: Topped crude obtained by refinery operations including light and heavy grades 5 and 6, heavy diesel fuel, type S-M diesel fuel, navy grade, navy special, bunker C, and acid sludge.

Royalty: A contractual arrangement providing a mineral interest that gives the owner a right to a fractional share of production or proceeds therefrom, that does not contain rights and obligations of operating a mineral property, and that is normally free and clear of exploration, developmental, and operating costs, except production taxes.

Short Ton: A unit of weight that equals 2,000 pounds.

Support Equipment and Facilities: These include, but are not limited to, seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

Tangible Development Costs: Cost incurred during the development stage for access, mineral-handling, and support facilities having a physical nature. In mining, such costs would include tracks, lighting equipment, ventilation equipment, other equipment installed in the mine to facilitate the extraction of minerals, and supporting facilities for housing and care of work forces. In the oil and gas industry, tangible development costs would include well equipment (such as casing, tubing, pumping equipment, and well heads), as well as field storage tanks and gathering systems.

Tar Sands: Naturally occurring bitumen-impregnated sands that yield mixtures of liquid hydrocarbon and that require further processing other than mechanical blending before becoming finished petroleum products.

Timing Differences: Differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. Timing differences originate in one period and reverse or "turn around" in one or more subsequent periods. Some timing differences reduce income taxes that would otherwise be payable currently; others increase income taxes that would otherwise be payable currently.

Transfer Price: The monetary value assigned to products, services, or rights conveyed or exchanged between related parties, including those occurring between units of a consolidated entity.

Uncompleted Wells, Equipment, and Facilities Costs: The costs incurred to (1) drill and equip wells that are not yet completed, and (2) acquire or construct equipment and facilities that are not yet completed and installed.

Undeveloped Property: Refers to a mineral property on which development wells or mines have not been drilled or completed to a point that would permit the production of commercial quantities of mineral reserves.

Uranium Oxide: The final precipitate formed in the uranium milling process. U_3O_8, a common form of triuranium oxide, is the powder obtained by evaporating an ammonial solution of the oxide.

Well: A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.

Wells are classified as (1) oil wells; (2) gas wells; (3) dry holes; (4) stratigraphic test wells; or (5) service wells. The latter two types of wells are not counted for FRS reporting.

Oil wells, gas wells, and dry holes are classified as exploratory wells or development wells. Exploratory wells are subclassified as (1) new-pool wildcats; (2) deeper-pool tests; (3) shallow-pool test; and (4) outpost (extension) tests. Well classifications reflect the status of wells after drilling has been completed.

- **Completion.** The term refers to the installation of permanent equipment for the production of oil or gas.
- **Development Well.** A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
- **Dry Hole.** An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
- **Exploratory Well.** A well that is not a development well, a service well, nor a stratigraphic test as those items are defined elsewhere.
- **Oil Well.** A well completed for the production of crude oil from at least one oil zone or reservoir.

Wellhead Price: The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts or tax regulations should be used where applicable.

Working Interest: An interest in a mineral property that entitles the owner of that interest to all of a share of mineral production from the property, usually subject to a royalty.

A working interest permits the owner to explore, develop and operate the property. The working interest owner bears the costs of exploration, development, and operation of the property, and in return is entitled to a share of the mineral production from the property, or to a share of the proceeds therefrom. It may be assigned to another party in whole or in part, or it may be divided into other special property interests.

- **Gross Working Interest.** The reporting company's working interest plus the proportionate share of any basic royalty interest or overriding royalty interest related to the working interest.

- **Net Working Interest.** The reporting company's working interest not including any basic royalty or overriding royalty interests.

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